CONSOL Energy Inc
Form 10-K
February 10, 2011
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934.**
For the fiscal year ended December 31, 2010;

OR

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from __________ to __________

Commission file number: 001-14901

CONSOL ENERGY INC.

(Exact name of registrant as specified in its charter)

Delaware	**51-0337383**

(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

CNX Center

1000 CONSOL Energy Drive

Canonsburg, PA 15317-6506

(Address of principal executive offices including zip code)

Registrant s telephone number including area code: 724-485-4000

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of exchange on which registered
Common Stock ($.01 par value)	New York Stock Exchange
Preferred Share Purchase Rights	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No ¨

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every interactive data file required to be submitted and posted pursuant to Rule 405 of Regulation S-T (Section 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (Section 229.405) is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one)

Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ¨ No x

The aggregate market value of voting stock held by nonaffiliates of the registrant as of June 30, 2010, the last business day of the registrant s most recently completed second fiscal quarter, based on the closing price of the common stock on the New York Stock Exchange on such date was $7,615,554,265.

The number of shares outstanding of the registrant s common stock as of January 28, 2011 is 226,236,682 shares.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of CONSOL Energy s Proxy Statement for the Annual Meeting of Shareholders to be held on May 4, 2011,

are incorporated by reference in Items 10, 11, 12, 13 and 14 of Part III.

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FORWARD-LOOKING STATEMENTS

We are including the following cautionary statement in this Annual Report on Form 10-K to make applicable and take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by, or on behalf of us. With the exception of historical matters, the matters discussed in this Annual Report on Form 10-K are forward-looking statements (as defined in Section 21E of the Exchange Act) that involve risks and uncertainties that could cause actual results to differ materially from projected results. Accordingly, investors should not place undue reliance on forward-looking statements as a prediction of actual results. The forward-looking statements may include projections and estimates concerning the timing and success of specific projects and our future production, revenues, income and capital spending. When we use the words believe, intend, expect, may, should, anticipate, could, estimate, plan, pr their negatives, or other similar expressions, the statements which include those words are usually forward-looking statements. When we describe strategy that involves risks or uncertainties, we are making forward-looking statements. The forward-looking statements in this Annual Report on Form 10-K speak only as of the date of this Annual Report on Form 10-K; we disclaim any obligation to update these statements unless required by securities law, and we caution you not to rely on them unduly. We have based these forward-looking statements on our current expectations and assumptions about future events. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. These risks, contingencies and uncertainties relate to, among other matters, the following:

- deterioration in economic conditions in any of the industries in which our customers operate, or sustained uncertainty in financial markets cause conditions we cannot predict;
- an extended decline in prices we receive for our coal and gas affecting our operating results and cash flows;
- our customers extending existing contracts or entering into new long-term contracts for coal;
- our reliance on major customers;
- our inability to collect payments from customers if their creditworthiness declines;
- the disruption of rail, barge, gathering, processing and transportation facilities and other systems that deliver our coal and gas to market;
- a loss of our competitive position because of the competitive nature of the coal and gas industries, or a loss of our competitive position because of overcapacity in these industries impairing our profitability;
- our ability to negotiate a new agreement with the United Mine Workers of America and our inability to maintain satisfactory labor relations;
- coal users switching to other fuels in order to comply with various environmental standards related to coal combustion emissions;
- the impact of potential, as well as any adopted regulations relating to greenhouse gas emissions on the demand for coal and natural gas, as well as the impact of any adopted regulations on our coal mining operations due to the venting of coalbed methane which occurs during mining;

foreign currency fluctuations could adversely affect the competitiveness of our coal abroad;

the risks inherent in coal and gas operations being subject to unexpected disruptions, including geological conditions, equipment failure, timing of completion of significant construction or repair of equipment, fires, explosions, accidents and weather conditions which could impact financial results;

our focus on new gas development projects and exploration for gas in areas where we have little or no proven gas reserves;

decreases in the availability of, or increases in, the price of commodities and services used in our mining and gas operations, as well as our exposure under take or pay contracts we entered into with well service providers to obtain services of which if not used could impact our cost of production;

obtaining and renewing governmental permits and approvals for our coal and gas operations;

the effects of government regulation on the discharge into the water or air, and the disposal and clean-up of, hazardous substances and wastes generated during our coal and gas operations;

the effects of stringent federal and state employee health and safety regulations, including the ability of regulators to shut down a mine or well;

the potential for liabilities arising from environmental contamination or alleged environmental contamination in connection with our past or current coal and gas operations;

the effects of mine closing, reclamation, gas well closing and certain other liabilities;

uncertainties in estimating our economically recoverable coal and gas reserves;

costs associated with perfecting title for coal or gas rights on some of our properties;

the outcomes of various legal proceedings, which are more fully described in our reports filed under the Securities Exchange Act of 1934;

the impacts of various asbestos litigation claims;

increased exposure to employee related long-term liabilities;

increased exposure to multi-employer pension plan liabilities;

minimum funding requirements by the Pension Protection Act of 2006 (the Pension Act) coupled with the significant investment and plan asset losses suffered during the recent economic decline has exposed us to making additional required cash contributions to fund the pension benefit plans which we sponsor and the multi-employer pension benefit plans in which we participate;

lump sum payments made to retiring salaried employees pursuant to our defined benefit pension plan exceeding total service and interest cost in a plan year;

acquisitions that we recently have completed or may make in the future including the accuracy of our assessment of the acquired businesses and their risks, achieving any anticipated synergies, integrating the acquisitions and unanticipated changes that could affect assumptions we may have made and divestitures we anticipate may not occur or produce anticipated proceeds;

the anti-takeover effects of our rights plan could prevent a change of control;

increased exposure on our financial performance due to the degree we are leveraged;

replacing our natural gas reserves, which if not replaced, will cause our gas reserves and gas production to decline;

our ability to acquire water supplies needed for gas drilling, or our ability to dispose of water used or removed from strata in connection with our gas operations at a reasonable cost and within applicable environmental rules;

our hedging activities may prevent us from benefiting from price increases and may expose us to other risks;

other factors discussed in this 2010 Form 10-K under Risk Factors, as updated by any subsequent Form 10-Qs, which are on file at the Securities and Exchange Commission.

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Item 1. ***Business.***
CONSOL Energy s History

We are a multi-fuel energy producer and energy services provider primarily serving the electric power generation industry in the United States. The electric power industry generates over two-thirds of its output by burning coal or gas, the two fuels we produce. During the year ended December 31, 2010, we produced high-British thermal unit (Btu) bituminous coal from 13 mining complexes in the United States. Coal produced from our mines has a high-Btu content which creates more energy per unit when burned compared to coals with lower Btu content. As a result, coals with greater Btu content can be more efficient to use. We produce pipeline-quality coalbed methane gas from our coal properties in the Northern and the Central Appalachian basin, and oil and gas from properties in the Appalachian and Illinois Basins. We believe that the use of coal and gas will continue to be the principal way in which the United States generates its electricity.

Historically, we rank among the largest coal producers in the United States based upon total revenue, net income and operating cash flow. Our production of approximately 62 million tons of coal in 2010 accounted for approximately 6% of the total tons produced in the United States and almost 14% of the total tons produced east of the Mississippi River during 2010. We are one of the premier coal producers in the United States by several measures:

- We mine more high-Btu bituminous coal than any other United States producer;
- We are the largest coal producer east of the Mississippi River;
- We control the largest amount of recoverable coal reserves east of the Mississippi River;
- We control the second largest amount of recoverable coal reserves among United States coal producers; and
- We are the largest United States producer of coal from underground mines.

CONSOL Energy is a leader in developing unconventional gas resources. CONSOL Energy is an industry leader in the development of coalbed methane production in the Eastern United States and is also a leader in the development of the Marcellus shale. CONSOL Energy holds considerable positions in other unconventional plays including: Chattanooga, New Albany, Huron and Utica shales. We also hold a large position in conventional Appalachian assets from the acquisition of the Appalachian oil and gas exploration and production business of Dominion Resources, Inc. (Dominion Acquisition). Our position as a gas producer is highlighted by several measures:

- Our principal coalbed methane operations produce gas from coal seams (single layers or strata of coal) with a high gas content;
- We produced 127.9 billion cubic feet of gas in the year ended December 31, 2010;
- At December 31, 2010, we had 12,587 net producing wells; and
- We controlled approximately 3.7 trillion cubic feet of net proved reserves at December 31, 2010, of which 48% were coalbed methane reserves.

Additionally, we provide energy services, including river and dock services, terminal services, industrial supply services, coal waste disposal services and land resource management services.

CONSOL Energy was organized as a Delaware corporation in 1991. We use CONSOL Energy to refer to CONSOL Energy Inc. and our subsidiaries, unless the context otherwise requires.

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Industry Segments

CONSOL Energy has two principal business divisions: Coal and Gas. The principal activities of the Coal Division are mining, preparation and marketing of steam coal, sold primarily to the electric power generation industry, and metallurgical coal, sold to metal and coke producers. The Coal Division includes four reportable segments. These reportable segments are Steam, Low Volatile Metallurgical, High Volatile Metallurgical and Other Coal. Each of these reportable segments includes a number of operating segments (mines or type of coal sold). For the year ended December 31, 2010, the Steam coal aggregated segment includes the following mines: Bailey, Blacksville #2, Buchanan, Emery, Enlow Fork, Fola Complex, Loveridge, McElroy, Miller Creek Complex, Robinson Run and Shoemaker. For the year ended December 31, 2010, the Low Volatile Metallurgical coal aggregated segment includes the Buchanan mine. For the year ended December 31, 2010, the High Volatile Metallurgical coal aggregated segment includes: Bailey, Blacksville #2, Enlow Fork, Fola Complex and Emery coal sales. The Other Coal segment includes our purchased coal activities, idled mine activities, as well as various other activities assigned to the coal division but not allocated to each individual mine. The principal activity of the Gas division is to produce pipeline quality methane gas for sale primarily to gas wholesalers. The Gas Division includes four reportable segments. These reportable segments are Coalbed Methane, Marcellus, Conventional and Other Gas. The Other Gas segment includes our purchased gas activities as well as various other activities assigned to the gas division but not allocated to each individual well type. CONSOL Energy s All Other segment includes terminal services, river and dock services, industrial supply services and other business activities. Financial Information concerning industry segments, as defined by accounting principles generally accepted in the United States, for the years ended December 31, 2010, 2009 and 2008 is included in Note 25 Segment Information in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K and incorporated herein.

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Coal Operations

Mining Complexes

During the year ended December 31, 2010, CONSOL Energy had 13 active mining complexes, including two 49% equity affiliates, all located in the United States.

The following map provides the location of CONSOL Energy s operations by region:

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The following table provides the location of CONSOL Energy s mining complexes and the coal reserves associated with each.

CONSOL ENERGY MINING COMPLEXES

Proven and Probable Assigned and Accessible Coal Reserves as of December 31, 2010 and 2009

Mine/Reserve	Location	Reserve Class	Coal Seam	Average Seam Thickness (feet)	As Received Heat Value(1) (Btu/lb) Typical	Range		Recoverable Reserves(2) Owned (%)	Leased (%)	Tons in Millions 12/31/2010	Recoverable Reserves (tons in Millions) 12/31/2009
ASSIGNED OPERATING											
Steam Reserves											
Enlow Fork(4)	Enon, PA	Assigned	Pittsburgh	5.4	12,940	12,860	13,060	100%	%	38.7	48.9
		Accessible	Pittsburgh	5.3	12,900	12,830	13,000	79%	21%	197.9	197.9
Bailey(4)	Enon, PA	Assigned	Pittsburgh	5.7	12,950	12,860	13,060	44%	56%	112.3	74.5
		Accessible	Pittsburgh	5.6	12,900	12,830	13,000	90%	10%	334.3	382.8
McElroy	Glen Easton, WV	Assigned	Pittsburgh	5.7	12,570	12,450	12,650	100%	%	7.4	195.0
		Accessible	Pittsburgh	5.8	12,530	12,410	12,610	94%	6%	153.1	153.0
Shoemaker	Moundsville, WV	Assigned	Pittsburgh	5.6	12,200	11,700	12,300	100%	%	44.5	48.4
		Accessible	Pittsburgh	5.6	12,250	11,990	12,390	100%	%	27.8	27.8
Loveridge	Metz, WV	Assigned	Pittsburgh	7.5	13,050	12,850	13,150	81%	19%	32.0	37.9
		Accessible	Pittsburgh	7.6	13,000	12,820	13,100	95%	5%	13.6	13.6
Robinson Run	Shinnston, WV	Assigned	Pittsburgh	7.4	12,940	12,600	13,300	87%	13%	52.7	58.2
		Accessible	Pittsburgh	6.8	12,940	12,600	13,300	55%	45%	156.7	156.7
Blacksville #2(4)	Wana, WV	Assigned	Pittsburgh	6.7	13,050	12,800	13,150	85%	15%	24.7	29.1
		Accessible	Pittsburgh	6.9	13,000	12,800	13,100	99%	1%	16.5	16.5
Harrison Resources(3)	Cadiz, OH	Assigned	Multiple	4.5	11,570	11,350	11,850	100%	%	7.1	9.2
Amvest-Fola Complex(4)	Bickmore, WV	Assigned	Multiple	3.6	12,380	12,250	12,550	92%	8%	53.3	101.7
Miller Creek Complex	Delbarton, WV	Assigned	Multiple	8.0	12,000	11,600	12,650	15%	85%	9.0	10.0
Emery(4)	Emery Co., UT	Assigned	Ferron I	7.5	12,260	12,000	13,000	71%	29%	17.9	16.9
Metallurgical Reserves											
Buchanan	Mavisdale, VA	Assigned	Pocahontas 3	5.7	13,980	13,700	14,200	20%	80%	63.7	68.4
		Accessible	Pocahontas 3	6.0	13,930	13,650	14,150	10%	90%	37.0	37.0
Western Allegheny Knob Creek(3)	Young Township, PA	Assigned	Upper Kittaning	3.2	13,050	13,000	13,100	100%	%	2.4	
Total Assigned Operating and Accessible										**1,402.6**	**1,683.5**

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(1) The heat value shown for assigned reserves is based on the quality of coal mined and processed during the year ended December 31, 2010. The heat value shown for accessible reserves is based on the same mining and processing methods as for the assigned reserves with adjustments made based on the variability found in exploration drill core samples. The heat values given have been adjusted to include moisture that may be added during mining or processing and for dilution by rock lying above or below the coal seam.
(2) Recoverable reserves are calculated based on the area in which mineable coal exists, coal seam thickness and average density determined by laboratory testing of drill core samples. This calculation is adjusted to account for coal that will not be recovered during mining and for losses that occur if the coal is processed after mining. Reserve calculations do not include adjustments for moisture that may be added during mining or processing, nor do the calculations include adjustments for dilution from rock lying above or below the coal seam. Reserves are reported only for those coal seams that are controlled by ownership or leases.
(3) Harrison Resources and Western Allegheny Knob Creek are both equity affiliates in which CONSOL Energy owns a 49% interest. Reserves reported equal CONSOL Energy s 49% proportionate interest in Harrison Resources and Western Allegheny Knob Creek s reserves.
(4) A portion of these reserves contain metallurgical qualities and are currently being sold on the metallurgical market.

Excluded from the table above are approximately 233.6 million tons of reserves at December 31, 2010 that are assigned to projects that have not produced coal in 2010. These assigned reserves are in the Northern Appalachia (northern West Virginia and Pennsylvania), Central Appalachia (Virginia and eastern Kentucky) and Illinois Basin (Illinois) regions. These reserves are approximately 61% owned and 39% leased.

CONSOL Energy assigns coal reserves to each of our mining complexes. The amount of coal we assign to a mining complex generally is sufficient to support mining through the duration of our current mining permit. Under federal law, we must renew our mining permits every five years. All assigned reserves have their required permits or governmental approvals, or there is a high probability that these approvals will be secured.

In addition, our mining complexes may have access to additional reserves that have not yet been assigned. We refer to these reserves as accessible. Accessible reserves are proven and probable unassigned reserves that can be accessed by an existing mining complex, utilizing the existing infrastructure of the complex to mine and to process the coal in this area. Mining an accessible reserve does not require additional capital spending beyond that required to extend or to continue the normal progression of the mine, such as the sinking of airshafts or the construction of portal facilities.

Some reserves may be accessible by more than one mining complex because of the proximity of many of our mining complexes to one another. In the table above, the accessible reserves indicated for a mining complex are based on our review of current mining plans and it reflects our best judgment as to which mining complex is most likely to utilize the reserve.

Assigned and unassigned coal reserves are proven and probable reserves which are either owned or leased. The leases have terms extending up to 30 years and generally provide for renewal through the anticipated life of the associated mine. These renewals are exercisable by the payment of minimum royalties. Under current mining plans, assigned reserves reported will be mined out within the period of existing leases or within the time period of probable lease renewal periods.

Coal Reserves

At December 31, 2010, CONSOL Energy had an estimated 4.4 billion tons of proven and probable reserves. Reserves are the portion of the proven and probable tonnage that meet CONSOL Energy s economic criteria regarding mining height, preparation plant recovery, depth of overburden and stripping ratio. Generally, these reserves would be commercially mineable at year-end price and cost levels.

Reserves are defined in Securities and Exchange Commission (SEC) Industry Guide 7 as that part of a mineral deposit which could be economically and legally extracted or produced at the time of the reserve determination. Proven and probable coal reserves are defined by SEC Industry Guide 7 as follows:

Proven (Measured) Reserves Reserves for which (a) quantity is computed from dimensions revealed in outcrops, trenches, workings or drill holes; grade and/or quality are computed from the results of detailed sampling and (b) the sites for inspection, sampling and measurement are spaced so close and the geologic character is so well defined that size, shape, depth and mineral content of reserves are well-established.

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Probable (Indicated) Reserves Reserves for which quantity and grade and/or quality are computed from information similar to that used for proven (measured) reserves, but the sites for inspection, sampling and measurement are farther apart or are otherwise less adequately spaced. The degree of assurance, although lower than that for proven (measured) reserves, is high enough to assume continuity between points of observation.

Spacing of points of observation for confidence levels in reserve calculations is based on guidelines in U.S. Geological Survey Circular 891 (Coal Resource Classification System of the U.S. Geological Survey). Our estimates for proven reserves have the highest degree of geologic assurance. Estimates for proven reserves are based on points of observation that are equal to or less than 0.5 mile apart. Estimates for probable reserves have a moderate degree of geologic assurance and are computed from points of observation that are between 0.5 to 1.5 miles apart.

An exception is made concerning spacing of observation points with respect to our Pittsburgh coal seam reserves. Because of the well-known continuity of this seam, spacing requirements are 3,000 feet or less for proven reserves and between 3,000 and 8,000 feet for probable reserves.

CONSOL Energy s estimates of proven and probable reserves do not rely on isolated points of observation. Small pods of reserves based on a single observation point are not considered; continuity between observation points over a large area is necessary for proven or probable reserves.

Our reserve estimates are predicated on information obtained from our ongoing exploration drilling and in-mine sampling programs. Data including coal seam elevation, thickness, and, where samples are available, coal quality is entered into a computerized geological database. This information is then combined with data on ownership or control of the mineral and surface interests to determine the extent of reserves in a given area. Reserve estimates include mine recovery rates that reflect CONSOL Energy s experience in various types of underground and surface coal mines.

CONSOL Energy s reserve estimates are based on geological, engineering and market data assembled and analyzed by our staff of geologists and engineers located at individual mines, operations offices and at our principal office. The reserve estimates are reviewed and adjusted annually to reflect production of coal from reserves, analysis of new engineering and geological data, changes in property control, modification of mining methods and other factors. Information, including the quantity and quality of reserves, coal and surface control, and other information relating to CONSOL Energy s coal reserve and land holdings, is maintained through a system of interrelated computerized databases.

Our estimate of proven and probable coal reserves has been determined by CONSOL Energy s geologists and mining engineers. Our coal reserves are periodically reviewed by an independent third party consultant. The independent consultant has reviewed the procedures used by us to prepare our internal estimates, verified the accuracy of our property reserve estimates and retabulated reserve groups according to standard classifications of reliability.

CONSOL Energy s proven and probable coal reserves fall within the range of commercially marketed coals in the United States. The marketability of coal depends on its value-in-use for a particular application, and this is affected by coal quality, such as, sulfur content, ash and heating value. Modern power plant boiler design aspects can compensate for coal quality differences that occur. Therefore, any of CONSOL Energy s coals can be marketed for the electric power generation industry.

CONSOL Energy s reserves are located in northern Appalachia (63%), central Appalachia (13%), the mid-western United States (18%), the western United States (4%), and in western Canada (2%) at December 31, 2010.

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The following table sets forth our unassigned proven and probable reserves by region:

CONSOL Energy UNASSIGNED Recoverable Coal Reserves as of December 31, 2010 and 2009

			Recoverable Reserves(2)			Recoverable Reserves (tons in Millions)
Coal Producing Region	**As Received Heat Value(1) (Btu/lb)**		**Owned (%)**	**Leased (%)**	**Tons in Millions 12/31/2010**	**12/31/2009**
Northern Appalachia (Pennsylvania, Ohio, Northern West Virginia)	11,400	13,500	73%	27%	1,412.2	1,239.7
Central Appalachia (Virginia, Southern West Virginia, Eastern Kentucky)	11,900	14,200	45%	55%	327.7	301.4
Illinois Basin (Illinois, Western Kentucky, Indiana)	11,500	11,900	43%	57%	777.9	780.6
Western U.S. (Wyoming)		9,400	100%	%	169.1	169.1
Western Canada (Alberta)	12,400	12,900	%	100%	77.9	77.9
Total			61%	39%	2,764.8	2,568.7

(1) The heat value estimates for Northern Appalachian and Central Appalachian unassigned coal reserves include adjustments for moisture that may be added during mining or processing as well as for dilution by rock lying above or below the coal seam. The mining and processing methods currently in use are used for these estimates. The heat value estimates for the Illinois Basin, Western U.S. and Western Canada unassigned reserves are based primarily on exploration drill core data that may not include adjustments for moisture added during mining or processing or for dilution by rock lying above or below the coal seam.

(2) Recoverable reserves are calculated based on the area in which mineable coal exists, coal seam thickness, and average density determined by laboratory testing of drill core samples. This calculation is adjusted to account for coal that will not be recovered during mining and for losses that occur if the coal is processed after mining. Reserve calculations do not include adjustment for moisture that may be added during mining or processing, nor do the calculations include adjustments for dilution from rock lying above or below the coal seam.

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The following table summarizes our proven and probable reserves as of December 31, 2010 by region and type of coal or sulfur content (sulfur content per million British thermal units). Proven and probable reserves include both assigned and unassigned reserves. The table classifies bituminous coal by rank. Rank (High volatile A, B and C) of bituminous coals are classified on the basis of heat value. The table also classifies bituminous coals as medium and low volatile which are classified on the basis of fixed carbon and volatile matter. Coal is ranked by the degree of alteration it has undergone since the initial deposition of the organic material. The lowest ranked coal, lignite, has undergone less transformation than the highest ranked coal, anthracite. From the lowest to the highest rank, the coals are: lignite; sub-bituminous; bituminous and anthracite. The ranking is determined by measuring the fixed carbon to volatile matter ratio and the heat content of the coal. As rank increases, the amount of fixed carbon increases, volatile matter decreases, and heat content increases. Bituminous coals are further characterized by the amount of volatile matter present. Bituminous coals with high volatile matter content are also ranked. High volatile A bituminous coals have higher heat content than high volatile C bituminous coals. These characterizations of coal allow a user to predict the behavior of a coal when burned in a boiler to produce heat or when it is heated in the absence of oxygen to produce coke for steel production.

CONSOL Energy Proven and Probable Recoverable Coal Reserves

By Producing Region and Product (In Millions of Tons) As of December 31, 2010

	£1.20 lbs. S02/MMBtu			>1.20 £ 2.50 lbs. S02/MMBtu			> 2.50 lbs. S02/MMBtu				
By Region	**Low Btu**	**Med Btu**	**High Btu**	**Low Btu**	**Med Btu**	**High Btu**	**Low Btu**	**Med Btu**	**High Btu**	**Total**	**Percentage By Region**
Northern Appalachia:											
Metallurgical:											
High Vol A Bituminous						164.7				164.7	3.7%
Steam:											
High Vol A Bituminous						111.3	62.2	119.6	2,279.2	2,572.3	58.4%
Low Vol Bituminous						33.6				33.6	0.8%
Region Total						309.6	62.2	119.6	2,279.2	2,770.6	62.9%
Central Appalachia:											
Metallurgical:											
High Vol A Bituminous		3.0	53.6			2.8			1.3	60.7	1.4%
Med Vol Bituminous			110.0			2.9				112.9	2.6%
Low Vol Bituminous			119.8			26.2				146.0	3.3%
Steam:											
High Vol A Bituminous	26.3	71.8	4.5	32.8	26.3	62.2		1.1	3.6	228.6	5.2%
Region Total	26.3	74.8	287.9	32.8	26.3	94.1		1.1	4.9	548.2	12.5%
Midwest-Illinois Basin:											
Steam:											
High Vol B Bituminous					79.3			457.9		537.2	12.2%
High Vol C Bituminous					159.5		108.3			267.8	6.1%
Region Total					238.8		108.3	457.9		805.0	18.3%
Northern Powder River Basin:											
Steam:											
Sub Bituminous B			169.1							169.1	3.8%
Region Total			169.1							169.1	3.8%
Utah-Emery Field:											
Steam:											
High Vol B Bituminous		17.9			12.3					30.2	0.7%
Region Total		17.9			12.3					30.2	0.7%
Western Canada:											
Metallurgical:											
Med Vol Bituminous	30.2	47.7								77.9	1.8%
Region Total	30.2	47.7								77.9	1.8%

Total Company	56.5	140.4	457.0	32.8	277.4	403.7	170.5	578.6	2,284.1	4,401.0	100.0%
Percent of Total	1.3%	3.2%	10.4%	0.7%	6.3%	9.2%	3.9%	13.1%	51.9%	100.0%	

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The following table classifies CONSOL Energy coals by rank, projected sulfur dioxide emissions and heating value (British thermal units per pound). The table also classifies bituminous coals as medium and low volatile which is based on fixed carbon and volatile matter.

CONSOL Energy Proven and Probable Recoverable Coal Reserves

By Product (In Millions of Tons) As of December 31, 2010

	£1.20 lbs. S02/MMBtu			>1.20 £ 2.50 lbs. S02/MMBtu			> 2.50 lbs. S02/MMBtu				
By Product	**Low Btu**	**Med Btu**	**High Btu**	**Low Btu**	**Med Btu**	**High Btu**	**Low Btu**	**Med Btu**	**High Btu**	**Total**	**Percentage By Product**
Metallurgical:											
High Vol A Bituminous		3.0	53.6			167.5			1.3	225.4	5.1%
Med Vol Bituminous	30.2	47.7	110.0			2.9				190.8	4.3%
Low Vol Bituminous			119.8			26.2				146.0	3.3%
Total Metallurgical	30.2	50.7	283.4			196.6			1.3	562.2	12.7%
Steam:											
High Vol A Bituminous	26.3	71.8	4.5	32.8	26.3	173.5	62.2	120.7	2,282.8	2,800.9	63.6%
High Vol B Bituminous		17.9			91.6			457.9		567.4	12.9%
High Vol C Bituminous					159.5		108.3			267.8	6.1%
Low Vol Bituminous						33.6				33.6	0.9%
Sub Bituminous B			169.1							169.1	3.8%
Total Steam	26.3	89.7	173.6	32.8	277.4	207.1	170.5	578.6	2,282.8	3,838.8	87.3%
Total	56.5	140.4	457.0	32.8	277.4	403.7	170.5	578.6	2,284.1	4,401.0	100.0%
Percent of Total	1.3%	3.2%	10.4%	0.7%	6.3%	9.2%	3.9%	13.1%	51.9%	100.0%	

The following table categorizes the relative Btu values (low, medium and high) for each of CONSOL Energy s producing regions in Btu s per pound of coal.

Region	**Low**	**Medium**		**High**
Northern, Central Appalachia and Canada	<12,500	12,500	13,000	>13,000
Midwest Appalachia	<11,600	11,600	12,000	>12,000
Northern Powder River Basin	< 8,400	8,400	8,800	> 8,800
Colorado and Utah	<11,000	11,000	12,000	>12,000

Compliance Compared to Non-Compliance Coal

Coals are sometimes characterized as compliance or non-compliance coal. The term compliance coal , as it is commonly used in the coal industry, refers to compliance only with former national sulfur dioxide emissions standards and indicates that when burned, the coal will produce emissions that will not exceed 1.2 pounds of sulfur dioxide per million British thermal units (1.2lb S02/MM Btu). A coal considered a compliance coal for meeting this former sulfur dioxide standard may not meet an emission standard for a different pollutant such as mercury, and may not even meet newer sulfur emission standards for all power plants. Clean air regulations that further restrict sulfur dioxide emissions will likely significantly reduce the amount of coal that can be used without post-combustion emission control technologies. Currently, a compliance coal will meet the power plant emission standard of 1.2 lb S02/MM Btu of fuel consumed. At December 31, 2010, approximately 0.7 billion tons, or 15%, of our coal reserves met that standard as a compliance coal. It is likely that, within several years, no coal will be compliant because federal regulations will require emissions-control technology to be used regardless of the coal s sulfur content. In many cases, our customers have responded to ever-tightening emissions requirements by retrofitting flue gas desulfurization systems (scrubbers) to existing power plants. Because these systems remove sulfur dioxide before it is emitted into the atmosphere, those customers are less concerned about the sulfur content of our coal.

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As a result of a 1998 court decision forcing the establishment of mercury emissions standards for power plants, the Environmental Protection Agency (EPA) was required to promulgate a regulatory program for controlling mercury. CONSOL Energy coals have mercury contents typical for their rank and location (approximately 0.07-0.15 parts mercury on a dry coal basis). Since CONSOL Energy coals have high heating values, they have lower mercury contents on a weight per energy basis (typically measured in pounds per trillion Btu) than lower rank coals at a given mercury concentration. Eastern bituminous coals also tend to produce a greater proportion of flue gas mercury in the ionic or oxidized form (which is more easily captured by scrubbers installed for sulfur control) than sub-bituminous coal, including coals produced in the Powder River Basin. Both high rank and low rank coals are also amenable to other methods of controlling mercury emissions, such as by powder activated carbon injection. The EPA s proposed Clean Air Mercury Rule was vacated by a federal court ruling. The EPA is currently developing new regulations to control multiple hazardous air pollutants, including mercury, from coal-fired plants, the so-called MACT Rule, which is expected to be finalized in 2014. Some states have already adopted a control program for mercury emissions from coal-fired power plants.

Production

In the year ended December 31, 2010, 94% of CONSOL Energy s production came from underground mines and 6% from surface mines. Where the geology is favorable and reserves are sufficient, CONSOL Energy employs longwall mining systems in our underground mines. For the year ended December 31, 2010, 91% of our production came from mines equipped with longwall mining systems. Underground longwall systems are highly mechanized, capital intensive operations. Mines using longwall systems have a low variable cost structure compared with other types of mines and can achieve high productivity levels compared with those of other underground mining methods. Because CONSOL Energy has substantial reserves readily suitable to these operations, CONSOL Energy believes that these longwall mines can increase capacity at low incremental cost.

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The following table shows the production, in millions of tons, for CONSOL Energy s mines in the years ended December 31, 2010, 2009 and 2008, the location of each mine, the type of mine, the type of equipment used at each mine, method of transportation and the year each mine was established or acquired by us.

Mine	Location	Mine Type	Mining Equipment	Transportation	Tons Produced (in millions) 2010	2009	2008	Year Established or Acquired
Steam								
McElroy	Glen Easton, WV	U	LW/CM	CB B	10.1	9.9	9.6	1968
Bailey	Enon, PA	U	LW/CM	R R/B	9.8	10.4	10.0	1984
Enlow Fork Steam	Enon, PA	U	LW/CM	R R/B	9.1	11.1	11.1	1990
Loveridge	Metz, WV	U	LW/CM	R T	5.9	6.0	5.2	1956
Robinson Run	Shinnston, WV	U	LW/CM	R CB	5.5	5.6	5.6	1966
Blacksville #2(1)	Wana, WV	U	LW/CM	R R/B T	4.5	3.8	5.6	1970
Shoemaker(2)	Moundsville, WV	U	LW/CM	B	3.9	0.4	1.1	1966
Miller Creek Complex(3)	Delbarton, WV	U/S	CM /S/L	R T	3.0	3.2	3.1	2004
AMVEST Fola Complex(1)(3)	Bickmore, WV	U/S	A /S/L CM	R T	1.9	3.0	3.9	2007
Emery	Emery Co., UT	U	CM	T	1.0	1.2	1.1	1945
Harrison Resources(3)(4)	Cadiz, OH	S	S/L	R T	0.5	0.4	0.2	2007
Buchanan Steam(1)(5)	Mavisdale, VA	U	LW/CM	R	0.2	0.7	0.5	1983
Jones Fork Complex(1)(3)(6)	Mousie, KY	U/S	CM / S/L	R T	0.1	1.1	2.5	1992
Mine 84(1)	Eighty Four, PA	U	LW/CM	R R/B T		0.5	1.8	1998
AMVEST Terry Eagle Complex	Jodie, WV	U/S	CM /A /S/L	R T			0.4	2007
High Volatile Metallurgical								
Bailey Met	Enon, PA	U	LW/CM	R R/B	1.2			1984
Enlow Fork Met	Enon, PA	U	LW/CM	R R/B	1.1			1990
Western Allegheny Knob Creek(4)	Young Township, PA	U	CM	R T	0.1			2010
Low Volatile Metallurgical								
Buchanan(1)(5)	Mavisdale, VA	U	LW/CM	R	4.5	2.1	3.0	1983
Amonate Complex(1)	Amonate, VA	U/S	CM / S/L	R T			0.4	1925

A Auger

S Surface

U Underground

LW Longwall

CM Continuous Miner

S/L Stripping Shovel and Front End Loaders

R Rail

B Barge

R/B Rail to Barge

T Truck

CB Conveyor Belt

(1) Mine was idled for part of the year(s) presented due to market conditions.
(2) Mine was idled throughout most of 2009 due to converting from track haulage, to more efficient belt haulage to remove coal from the mine.

(3) Harrison Resources, Miller Creek Complex, Amvest Fola, Jones Fork and Western Allegheny Knob Creek include facilities operated by independent mining contractors.
(4) Production amounts represent CONSOL Energy s 49% ownership interest.
(5) Buchanan Mine was idled for part of the year ended December 31, 2008 after several roof falls in previously mined areas damaged some of the ventilation controls inside the mine.
(6) Complex was sold in March 2010.

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Our sales of bituminous coal were at average sales price per ton produced as follows:

		Years Ended December 31, 2010	2009	2008
Average Sales Price Per Ton Produced	Steam Coal	$ 53.48	$ 56.57	$ 45.01
Average Sales Price Per Ton Produced	High Volatile Met Coal	$ 75.27	$	$
Average Sales Price Per Ton Produced	Low Volatile Met Coal	$ 151.31	$ 104.16	$ 116.94
Average Sales Price Per Ton Produced	Total Company	$ 61.35	$ 58.28	$ 48.77

Construction of a new slope and overland belt at the Bailey Mine in Pennsylvania was completed in April 2010. Overland belt projects are expected to enhance safety, improve productivity, increase production and reduce costs. Modern conveyor systems typically provide high availability rates, thereby allowing mining equipment to produce at higher levels. Overland belts do not require the daily maintenance of the mine roof that underground haulage systems require allowing manpower to be reduced or redeployed to more productive work. Mine safety is expected to be enhanced by overland belts because older underground belt areas will be sealed. Construction of a new slope and overland belt at the Enlow Fork Mine in Pennsylvania began in 2010 and is expected to be completed by the end of December 2013.

A project to upgrade the Bailey Preparation Plant began in September 2010 and is expected to be completed by June 2011. This efficiency upgrade will include adding 10 screen bowls to the plant resulting in higher yield and cost savings.

Also, construction of a reverse osmosis water treatment system (RO) was started during 2009. The RO system will provide a constant water source to the Buchanan preparation plant and provide water needed in the underground coal production at the mine. Construction was completed in December 2010 and final commissioning of the RO system will be complete by the end of March 2011.

Title to coal properties that we lease or purchase and the boundaries of these properties are verified at the time we lease or acquire the properties by law firms retained by us. Consistent with industry practice, abstracts and title reports are reviewed and updated approximately five years prior to planned development or mining of the property. If defects in title or boundaries of undeveloped reserves are discovered in the future, control of and the right to mine reserves could be adversely affected.

The following table sets forth, with respect to properties that we lease to other coal operators, the total royalty tonnage, acreage leased and the amount of income (net of related expenses) we received from royalty payments for the years ended December 31, 2010, 2009 and 2008.

Year	Total Royalty Tonnage (in thousands)	Total Coal Acreage Leased	Total Royalty Income (in thousands)
2010	8,606	226,524	$ 14,073
2009	11,403	232,181	$ 16,448
2008	11,757	218,273	$ 18,775

Royalty tonnage leased to third parties is not included in the amounts of produced tons that we report. Proven and probable reserves do not include reserves attributable to properties that we lease to third parties.

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The following table ranks the 20 largest underground mines in the United States by tons of coal produced in calendar year 2009, the latest year for which statistics are available.

MAJOR U.S. UNDERGROUND COAL MINES 2009

In millions of tons

Mine Name	Operating Company	Production
Enlow Fork	**CONSOL Energy**	**11.1**
Bailey	**CONSOL Energy**	**10.4**
McElroy	**CONSOL Energy**	**9.9**
Twenty Mile	Peabody Energy Subsidiary	7.7
Cumberland	Pennsylvania Services (Alpha)	6.8
Powhatan No. 6	The Ohio Valley Coal Company (Murray)	6.7
SUFCO	Arch Coal, Inc.	6.6
San Juan	BHP Billiton	6.5
Warrior	Warrior Coal, LLC (Alliance)	6.2
Century	American Energy Corp. (Murray)	6.0
Loveridge	**CONSOL Energy**	**6.0**
Mach #1	Mach Mining, LLC	5.9
Elk Creek	Oxbow Mining, LLC	5.7
Emerald	Emerald Resources (Alpha)	5.6
Robinson Run	**CONSOL Energy**	**5.6**
Dotiki	Webster County Coal, LLC (Alliance)	4.2
West Elk	Arch Coal, Inc.	4.0
Elk Creek	Hopkins Country Coal, LLC (Alliance)	4.0
New Era	American Energy Corp. (Murray)	3.9
Blacksville 2	**CONSOL Energy**	**3.8**

Source: National Mining Association, EIA

Marketing and Sales

We sell coal produced by our mining complexes and additional coal that is purchased by us for resale from other producers. We maintain United States sales offices in Charlotte, Philadelphia and Pittsburgh. In addition, we sell coal through agents and to brokers and unaffiliated trading companies. In 2010, we sold 63.9 million tons of coal, including our portion of equity affiliates. Of these sales, 79% were sold in domestic markets. Our direct sales to domestic electricity generators represented 70% of our total tons sold in 2010. We had approximately 85 customers in 2010. During 2010, no coal customers individually accounted for more than 10% of total revenue. However, the top four coal customers accounted for more than 25% of our total revenues.

We announced in 2010 an exclusive agreement with Xcoal, who opened offices in Seoul, Beijing, Singapore, Tokyo and Delhi. This agreement provides CONSOL Energy s Northern Appalachia and Buchanan coals increased access to these growing Asian markets.

Coal Contracts

We sell coal to an established customer base through opportunities as a result of strong business relationships, or through a formalized bidding process. Contract volumes range from a single shipment to multi-year agreements for millions of tons of coal. The average contract term is between one to three years. However, several multi-year agreements have terms ranging from five to twenty years. As a normal course of business, efforts are made to renew or extend contracts scheduled to expire. Although there are no guarantees, we generally have been successful in renewing or extending contracts in the past. For the year ended December 31, 2010, over 89% of all the coal we produced was sold under contracts with terms of one year or more.

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The following table sets forth, as of January 8, 2011, the total tons of coal CONSOL Energy is committed to deliver from 2011 through 2015.

	Tons/Dollars of Coal to be Delivered (Tons in millions of nominal tons)				
	2011	2012	2013	2014	2015
Committed tons without pricing:					
Steam		20.5	20.2	21.7	20.0
High Volatile Met	0.7	0.2			
Low Volatile Met	1.5	2.6	2.3	0.4	
Total Company	2.2	23.3	22.5	22.1	20.0
Committed tons with firm pricing:					
Steam	52.6	22.3	11.5	4.8	2.2
High Volatile Met	0.7	0.4	0.3	0.2	0.2
Low Volatile Met	2.2	0.3	0.2	0.1	0.1
Total Company	55.5	23.0	12.0	5.1	2.5
Average realized price:					
Steam	$ 57.68	$ 61.49	$ 58.98	$ 49.14	$ 50.09
High Volatile Met	$ 77.20	$ 77.71	$ 93.43	$ 108.21	$ 110.92
Low Volatile Met	$ 160.70	$ 90.21	$ 81.82	$ 80.00	$ 80.00
Total Company	$ 62.03	$ 62.09	$ 60.08	$ 51.76	$ 55.48
Committed tons priced with collars*:					
Steam					
Tons		5.8	6.9	6.9	8.9
Average ceiling	$	$ 51.60	$ 56.88	$ 60.25	$ 59.64
Average floor	$	$ 43.07	$ 47.13	$ 46.88	$ 44.84

*There are no High or Low Volatile Met committed tons priced with collars.

Coal pricing for contracts with terms of one year or less is generally fixed. Coal pricing for multiple-year agreements generally provides the opportunity to periodically adjust the contract prices through pricing mechanisms consisting of one or more of the following:

Fixed price contracts with pre-established prices; or

Periodically negotiated prices that reflect market conditions at the time; or

Price restricted to an agreed-upon percentage increase or decrease; or

Base-price-plus-escalation methods which allow for periodic price adjustments based on inflation indices.

The volume of coal to be delivered is specified in each of our coal contracts. Although the volume to be delivered under the coal contracts is stipulated, the parties may vary the timing of the deliveries within specified limits.

Coal contracts typically contain force majeure provisions allowing for the suspension of performance by either party for the duration of specified events. Force majeure events include, but are not limited to, labor disputes and unexpected significant geological conditions. Depending on the language of the contract, some contracts may terminate upon continuance of an event of force majeure that extends for a period greater than three to twelve months.

Distribution

Coal is transported from CONSOL Energy s mining complexes to customers by means of railroad cars, river barges, trucks, conveyor belts or a combination of these means of transportation. We employ transportation

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specialists who negotiate freight and equipment agreements with various transportation suppliers, including railroads, barge lines, terminal operators, ocean vessel brokers and trucking companies for certain customers. Most customers negotiate their own freight contracts.

At December 31, 2010 we operated 22 towboats, 5 harbor boats and a fleet of 620 barges that serve customers along the Ohio, Allegheny, Kanawha and Monongahela Rivers. The barge operation allows us to control delivery schedules and has served as temporary floating storage for coal when land storage is unavailable.

Competition

The United States coal industry is highly competitive, with numerous producers selling into all markets that use coal. CONSOL Energy competes against other large producers and hundreds of small producers in the United States and overseas. The five largest producers are estimated by the 2009 National Mining Association Survey to have produced approximately 53% (based on tonnage produced) of the total United States production in 2009. The U.S. Department of Energy reported 1,375 active coal mines in the United States in 2009, the latest year for which government statistics are available. Demand for our coal by our principal customers is affected by many factors including:

- the price of competing coal and alternative fuel supplies, including nuclear, natural gas, oil and renewable energy sources, such as hydroelectric power or wind;
- coal quality;
- transportation costs from the mine to the customer; and
- the reliability of fuel supply.

Continued demand for CONSOL Energy s coal and the prices that CONSOL Energy obtains are affected by demand for electricity, environmental and government regulation, technological developments and the availability and price of competing coal and alternative fuel supplies. We sell coal to foreign electricity generators and to the more specialized metallurgical coal markets, both of which are significantly affected by international demand and competition.

Gas Operations

Our gas operations primarily produce coalbed methane (CBM), which is gas that resides in coal seams. In the eastern United States, conventional natural gas fields typically are located in various types of sedimentary formations at depths ranging from 2,000 to 15,000 feet. Exploration companies often put their capital at risk by searching for gas in commercially exploitable quantities at these depths. By contrast, gas in the coal seams that we drill or anticipate drilling is typically found in formations less than 2,500 feet deep which are usually better defined than deeper formations. CONSOL Energy believes that this contributes to lower exploration costs than those incurred by producers that operate in deeper, less defined formations. Most of our CBM operations are located in central Appalachia in Southwest Virginia. CBM is our traditional and largest operation. Typically in this area we have produced CBM from vertical wells which we drill ahead of mining and gob gas wells which are drilled behind mining. Some of our CBM production comes from northern Appalachia in northwestern West Virginia and southwestern Pennsylvania where we drill vertical-to-horizontal CBM wells. In 2010, CBM production was 91.4 billion cubic feet (bcf) or 72% of our total gas production compared to 86.9 bcf, or 92% of our total gas production in 2009.

On April 30, 2010, CONSOL Energy completed the Dominion Acquisition for approximately $3.5 billion. The acquisition included approximately one trillion cubic feet equivalents (Tcfe) of net proved reserves and 1.46 million net acres of oil and gas rights within the Appalachian Basin. Included in the acreage holdings were approximately 500 thousand prospective net Marcellus Shale acres located predominantly in southwestern Pennsylvania and northern West Virginia. The producing wells acquired in the Dominion Acquisition are primarily vertical conventional wells located in northwest West Virginia and central Pennsylvania. The producing wells purchased in the acquisition have contributed to the increase in our conventional gas production

in the year ended December 31, 2010. In 2010, conventional production was 24.6 bcf or 19% of our total gas production compared to 1.7 bcf or 2% of total gas production in 2009.

With the Dominion Acquisition and other land activities, we have substantially increased our acreage position in the Marcellus Shale from approximately 250,000 at December 31, 2009 to approximately 752,000 at December 31, 2010. Our gas division has been focused on developing our Marcellus acreage position in southwest Pennsylvania, central Pennsylvania and northwest West Virginia. In the year ended December 31, 2010, we have drilled 24 horizontal Marcellus wells of which 13 were brought on-line. We also acquired 17 vertical Marcellus wells acquired in the Dominion Acquisition bringing our total well count to 52 Marcellus wells. Our horizontal Marcellus wells can have laterals up to 5,000 feet in length. Longer laterals allow for higher gas production with a proportionately smaller outlay of capital than drilling an additional vertical well with shorter laterals. These Marcellus wells produced 10.2 bcf in 2010 or 8% of our total gas production compared to 4.9 bcf or 5% of our total gas production in 2009.

We also have operations in central Ohio, eastern Tennessee, western Kentucky, Indiana and Illinois. We have continued to explore the shale and deeper formations in these areas. For example, we are conducting an exploration program in the Utica, the New Albany Shale and other shallow oil zones. In addition to these areas, we believe we have Appalachian shale potential in the Huron shale. Additional potential exists in the Trenton Black River formation which is thought to underlie nearly all of the Appalachian shales. We will continue to evaluate our acreage position in these areas with the continuation of our exploration program. Wells in these areas produced 1.7 bcf or 1% of our total gas production in 2010 compared to 0.9 bcf or less than 1% for our total gas production in 2009.

CONSOL Energy has not filed reserve estimates with any federal agency.

CBM

We have the rights to extract CBM in Virginia from approximately 356,000 net CBM acres, which cover a portion of our coal reserves in Central Appalachia. We produce gas primarily from the Pocahontas #3 seam which is the main coal seam mined by our Buchanan Mine. This seam is generally found at depths of 2,000 feet and generally ranges from 3 to 6 feet thick. The gas content of this seam is typically between 400 and 600 cubic feet of gas per ton of coal in place. In addition, there are as many as 50 thinner seams present in the several hundred feet above the main Pocahontas #3 seam. Collectively, this series of coal seams represents a total thickness ranging from 15 to 40 feet. We have access to core hole data that allows us to determine the amount of coal present, the geologic structure of the coal seam and the gas content of the coal.

We also have the right to extract CBM in northwestern West Virginia and southwestern Pennsylvania from approximately 858,000 net CBM acres, which contain most of our recoverable coal reserves in Northern Appalachia. We produce gas primarily from the Pittsburgh #8 coal seam. This seam is generally found at depths of less than 1,000 feet and generally ranges from 4 to 7 feet thick. The gas content of this seam is typically between 100 and 250 cubic feet of gas per ton of coal in place. There are additional coal seams above and below the Pittsburgh #8 seam. Collectively, this series of coal seams represents a total thickness ranging from 10 to 30 feet. We have access to information that allows us to determine the amount of coal present, the geologic structure of the coal seam and the gas content of the coal.

In central Pennsylvania we have the right to extract CBM from approximately 263,000 net CBM acres, which contain most of our recoverable coal reserves as well as significant leases from other coal owners. In addition, we control 841,000 net CBM acres in Illinois, Kentucky, Indiana, and Tennessee. We also have the right to extract CBM on 139,000 net acres in the San Juan Basin, 20,000 net acres in the Powder River Basin, and 92,000 net acres in eastern Ohio and central West Virginia.

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Marcellus Shale

We have substantially increased our acreage position in the Marcellus Shale from 250,000 net acres at December 31, 2009 to 752,000 net acres at December 31, 2010. The Dominion Acquisition contributed approximately 500,000 acres of the increase. CONSOL Energy drilled and completed 13 wells in the Marcellus Shale in southwestern and central Pennsylvania in 2010. The Dominion Acquisition also included 17 producing Marcellus wells, 12 of these wells are located in central Pennsylvania and 5 of these wells are located in northwestern West Virginia. We also had 11 Marcellus wells in process at December 31, 2010. At December 31, 2010 we have 52 producing Marcellus wells compared to 22 Marcellus wells in 2009.

Our Marcellus wells are primarily horizontal wells with 2,500 to 5,000 feet of lateral length. The longer lateral lengths allow for proportionately higher gas production from a single well compared to shorter length lateral wells. This allows for proportionately lower capital outlays compared to drilling shorter length lateral wells. The average lateral was 3,400 feet.

CONSOL Energy s primary 2011 gas objective is to delineate the newly acquired Marcellus Shale acreage in central Pennsylvania and northern West Virginia. We also plan to extend the average lateral length to 4,000 feet and complete more frac stages which should improve well economics.

Conventional

In 2010, the Dominion Acquisition significantly contributed to the increased number of conventional wells from 195 at December 31, 2009 to 8,517 at December 31, 2010. The conventional wells acquired in the Dominion Acquisition were primarily located in northwestern West Virginia and central Pennsylvania. In 2010, we drilled and completed 23 shallow conventional wells in central Pennsylvania. Also, in 2010, we drilled and completed 86 conventional wells in West Virginia, three conventional wells in Kentucky, and two conventional wells in eastern Ohio. Currently, 32 conventional wells are waiting for the completion of gathering facilities for collection.

The majority of our conventional leasehold position is held by production and all of it is extensively overlain by existing third party gas gathering and transmission infrastructure. Conventional drilling in West Virginia and central Pennsylvania is characterized as low-cost and low-risk with success rates exceeding 98%. The conventional assets add great diversity to CONSOL Energy s drilling portfolio, provide multiple synergies with our CBM and unconventional shale operations, and the held by production nature of the conventional properties affords CONSOL Energy considerable flexibility to choose when to exploit those assets.

CONSOL Energy also has the rights to extract conventional gas from approximately 650,000 net acres of shallow conventional potential in Ohio, Pennsylvania, West Virginia, and New York.

Other Gas

We control approximately 346,000 net acres of rights to gas in the New Albany shale in Kentucky, Illinois, and Indiana. The New Albany shale is a formation containing gaseous hydrocarbons, and our acreage position has thickness of 50-300 feet at an average depth of 2,500-4,000 feet. In 2010, we participated with RPSEA (Research Partnership to Secure Energy for America) to better understand and further pursue the development of the vast New Albany Shale resources. As part of that effort, we drilled and completed two horizontal New Albany Shale wells, retrieved full bore core and conducted micro seismic analysis. In addition, we conducted the first ever simultaneous VaporFrac, a mixture of 95% nitrogen and 5% liquid in the fracturing fluid, essentially minimizing the liquids used in fracing wells. Two additional horizontal wellbores to further test the New Albany shale are planned for 2011.

The Chattanooga Shale in Tennessee is a Devonian-age shale found at a depth of approximately 3,500 feet. Shale thickness is between 40-80 feet, and CONSOL Energy has found it to be rich in total organic content.

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CONSOL Energy has 282,000 net acres of Chattanooga Shale. This largely contiguous acreage is composed of only a small number of leases, a rarity in Appalachia. CONSOL Energy is the operator of all of its Chattanooga Shale wells. CONSOL Energy believes that we drilled the first successful horizontal Chattanooga Shale well and that we have currently drilled more horizontal wells than any other operator in this play.

We have 480,000 net acres of Huron shale potential in Kentucky and Virginia; a portion of this acreage has tight sands potential. CONSOL Energy also currently controls acreage in southeastern Ohio, southwestern Pennsylvania, and northern West Virginia underlain by Utica Shale potential. The thickness of the Utica Shale in this area ranges from 200 to 450 feet. Further delineation of this potential is planned for 2011, particularly in Ohio where the play is expected to be rich in liquid hydrocarbons.

Summary of Properties as of December 31, 2010

	Coalbed Methane Segment	Conventional Segment	Marcellus Segment	Other Gas Segment	Total
Estimated Net Proved Reserves (billion cubic feet equivalent)	1,789,385	983,589	859,396	99,227	3,731,597
Percent Developed	60%	70%	16%	25%	52%
Net Producing Wells (including gob wells)	3,945	8,517	52	73	12,587
Net Proved Developed Acres	254,683	226,154	2,074	7,558	490,469
Net Proved Undeveloped Acres	72,819	44,847	10,285	11,993	139,944
Net Unproved Acres(1)	2,241,748	378,825	739,977	1,088,004	4,448,554
Total Net Acres(2)	2,569,250	649,826	752,336	1,107,555	5,078,967

(1) Net acres include acreage attributable to our working interests of the properties. Additional adjustments (either increases or decreases) may be required as we further develop title to and further confirm our rights with respect to our various properties in anticipation of development. We believe that our assumptions and methodology in this regard are reasonable.

(2) Acreage amounts are shown under the target strata CONSOL Energy expects to produce, although the reported acre may include rights to multiple gas seams (CBM, Conventional, Marcellus, etc.). We have reviewed our drilling plans, our acreage rights and used our best judgment to reflect the acre in the strata we expect to produce. As more information is obtained or circumstances change, the acreage classification may change.

Development Wells (Net)

During the years ended December 31, 2010, 2009 and 2008 we drilled 317, 247 and 534 net development wells, respectively. Gob wells and wells drilled by other operators that we participate in are excluded. There was one dry development well in 2010 and one dry development well in 2009. There were no dry development wells in 2008. As of December 31, 2010, 21 wells are still in process. The following table illustrates the wells drilled by well classification type:

	For the Year Ended December 31,		
	2010	2009	2008
Coalbed methane segment	184	228	534
Conventional segment	107	5	
Marcellus segment	24	14	
Other Gas segment	2		
Total	317	247	534

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Exploratory Wells (Net)

During the years ended December 31, 2010, 2009 and 2008, we drilled in the aggregate 38, 18 and 56 net exploratory wells, respectively. The following table illustrates the exploratory wells drilled by well classification type:

	For the Year Ended December 31,								
	2010			2009			2008		
	Producing	Dry	Still Eval.	Producing	Dry	Still Eval.	Producing	Dry	Still Eval.
Coalbed methane segment				2			3		10
Conventional segment	2		3	2		2	3	3	10
Marcellus segment				2	1		3		
Other Gas segment	18	2	13	5		4	6		18
Total	20	2	16	11	1	6	15	3	38

Summary of Other Operating Data

Production

The following table sets forth net sales volumes produced for the periods indicated:

	For the Year Ended December 31,		
	2010	2009	2008
	(in million cubic feet)		
Coalbed methane segment	91,351	86,944	75,783
Conventional segment	24,599	1,663	174
Marcellus segment	10,195	4,950	394
Other Gas segment	1,730	858	211
Total Produced	127,875	94,415	76,562

Average Sales Price and Average Lifting Cost

The following table sets forth the total average sales price and the total average lifting cost for all of our gas production for the periods indicated, including intersegment transactions. Total lifting cost is the cost of raising gas to the gathering system and does not include depreciation, depletion or amortization. See Part II Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations for a breakdown by segment.

	For the Year Ended December 31,		
	2010	2009	2008
Average Gas Sales Price Before Effects of Financial Settlements (per thousand cubic feet)	$ 4.53	$ 4.15	$ 8.99
Average Effects of Financial Settlements (per thousand cubic feet)	$ 1.30	$ 2.53	$
Average Gas Sales Price Including Effects of Financial Settlements (per thousand cubic feet)	$ 5.83	$ 6.68	$ 8.99
Average Lifting Cost excluding ad valorem and severance taxes (per thousand cubic feet)	$ 0.50	$ 0.48	$ 0.58

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Producing Wells and Acreage

Most of our development wells and proved acreage are located in Virginia, West Virginia and Pennsylvania. Some leases are beyond their primary term, but these leases are extended in accordance with their terms as long as certain drilling commitments or other term commitments are satisfied. The following table sets forth, at December 31, 2010, the number of producing wells, developed acreage and undeveloped acreage:

	Gross	Net(1)
Producing Wells (including gob wells)	14,747	12,587
Proved Developed Acreage	520,005	490,469
Proved Undeveloped Acreage	146,173	139,944
Unproven Acreage	5,014,495	4,448,554
Total Acreage	5,680,673	5,078,967

(1) Net acres include acreage attributable to our working interests of the properties. Additional adjustments (either increases or decreases) may be required as we further develop title to and further confirm our rights with respect to our various properties in anticipation of development. We believe that our assumptions and methodology in this regard are reasonable.

We enter into physical gas sales transactions with various counterparties for terms varying in length. Reserves and production estimates are believed to be sufficient to satisfy these obligations. In the past, other than interstate pipeline outages related to maintenance issues or a weather related force majeure event, we have not failed to deliver quantities required under contract. We also enter into various gas swap transactions that qualify as financial cash flow hedges. These gas swap transactions exist parallel to the underlying physical transactions and represented approximately 52.1 billion cubic feet of our produced gas sales volumes for the year ended December 31, 2010 at an average price of $7.66 per thousand cubic feet. These financial hedges represented approximately 51.6 billion cubic feet of our produced gas sales volumes for the year ended December 31, 2009 at an average price of $8.76 per thousand cubic feet. As of December 31, 2010, we expect these transactions will cover approximately 48.0 billion cubic feet of our estimated 2011 production at an average price of $5.56 per thousand cubic feet, 22.6 billion cubic feet of our estimated 2012 production at an average price of $6.20 per thousand cubic feet, 3.8 billion cubic feet of our estimated 2013 production at an average price of $5.16 per thousand cubic feet, and 3.8 billion cubic feet of our estimated 2014 production at an average price of $5.41 per thousand cubic feet.

We have purchased firm transportation capacity on various interstate pipelines to ensure gas production flows to market. As of December 31, 2010, we have secured firm transportation capacity to cover more than our 2011, 2012, 2013 and 2014 hedged production.

The hedging strategy and information regarding derivative instruments used are outlined in Part II Item 7A Qualitative and Quantitative Disclosures About Market Risk and in Note 23 Derivative Instruments in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K.

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Reserves

The following table shows our estimated proved developed and proved undeveloped reserves. Reserve information is net of royalty interest. Proved developed and proved undeveloped reserves are reserves that could be commercially recovered under current economic conditions, operating methods and government regulations. Proved developed and proved undeveloped reserves are defined by the Securities and Exchange Commission (SEC).

	Net Reserves (Million cubic feet equivalent) as of December 31,		
	2010	**2009**	**2008**
Proved developed reserves	1,931,272	1,040,257	783,290
Proved undeveloped reserves	1,800,325	871,134	638,756
Total proved developed and undeveloped reserves(a)	3,731,597	1,911,391	1,422,046

(a) For additional information on our reserves, see Other Supplemental Information Supplemental Gas Data (unaudited) to the Consolidated Financial Statements in Item 8 of this Form 10-K.

Discounted Future Net Cash Flows

The following table shows our estimated future net cash flows and total standardized measure of discounted future net cash flows at 10%:

	Discounted Future Net Cash Flows (Dollars in millions)		
	2010	**2009**	**2008**
Future net cash flows	$ 5,474	$ 2,391	$ 2,824
Total PV-10 measure of pre-tax discounted future net cash flows(1)	$ 2,780	$ 1,480	$ 2,004
Total standardized measure of after tax discounted future net cash flows	$ 1,661	$ 894	$ 1,218

(1) We calculate our present value at 10% (PV-10) in accordance with the following table. Management believes that the presentation of the non-Generally Accepted Accounting Principle (GAAP) financial measure of PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and gas companies. Because many factors that are unique to each individual company impact the amount of future income taxes estimated to be paid, the use of a pre-tax measure is valuable when comparing companies based on reserves. PV-10 is not a measure of the financial or operating performance under GAAP. PV-10 should not be considered as an alternative to the standardized measure as defined under GAAP. We have included a reconciliation of the most directly comparable GAAP measure after-tax discounted future net cash flows.

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Reconciliation of PV-10 to Standardized Measure

	As of December 31,		
	2010	2009	2008
	(Dollars in millions)		
Future cash inflows	$ 16,724	$ 7,975	$ 8,857
Future production costs	(5,176)	(3,123)	(3,526)
Future development costs (including abandonments)	(2,720)	(996)	(794)
Future net cash flows (pre-tax)	8,828	3,856	4,537
10% discount factor	(6,048)	(2,376)	(2,533)
PV-10 (Non-GAAP measure)	2,780	1,480	2,004
Undiscounted income taxes	(3,354)	(1,465)	(1,714)
10% discount factor	2,235	879	928
Discounted income taxes	(1,119)	(586)	(786)
Standardized GAAP measure	$ 1,661	$ 894	$ 1,218

Midstream Gas Services

CONSOL Energy has traditionally designed, built and operated natural gas gathering systems to move gas from the wellhead to interstate pipelines or other local pricing points. In addition, CONSOL Energy acquired extensive gathering assets in the Dominion Acquisition in 2010. CONSOL Energy now owns approximately 3,000 miles of gas gathering pipelines as well as 230,000 horsepower of compression, of which, approximately 80% is wholly owned with the balance being leased. Along with this compression capacity, CONSOL Energy owns and operates a number of gas processing facilities. This infrastructure is capable of delivering 200 billion cubic feet per year of pipeline quality gas.

This in-place gas infrastructure was primarily built to transport CONSOL Energy s coalbed methane (CBM) production and shallow conventional gas. This system is generally not suited to move the higher pressure volumes associated with Marcellus wells. However, we believe that the network of right-of-ways, vast surface holdings and experience in building and operating gathering systems in the Appalachian basin will give CONSOL Energy a tremendous advantage in building the midstream assets required to develop CONSOL Energy s Marcellus position.

CONSOL Energy has had the advantage of having gas production from CBM, which can be lower Btu than pipeline specification, as well as higher Btu Marcellus production which can complement each other by reducing and in some cases eliminating the need for costly processing of the CBM. In addition, the lower Btu CBM production offers an opportunity to blend ethane back into the gas stream when pricing or capacity for ethane markets dictate. This will allow CONSOL Energy more flexibility in bringing Marcellus on-line at qualities that meet interstate pipeline specifications.

In addition to the pipeline and processing assets, CONSOL Energy has access to water resources. Through legacy mining operations overlapping the footprint of our gas resources, CONSOL Energy has access to mine waters and the infrastructure to move water to locations where water is needed to support future gas operations. We believe that there are synergies between mining and gas operations around water resources that could give unique advantages to CONSOL Energy.

Competition

The United States natural gas industry is highly competitive. CONSOL Energy competes with other large producers, thousands of small producers as well as pipeline imports from Canada and Liquefied Natural Gas

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(LNG) from around the globe. According to data from the Natural Gas Supply Association and the U.S. Department of Energy, the five largest producers of natural gas produced less than 19% of the total U.S. production in the first half of 2010. The U.S. Department of Energy reported almost 500,000 producing natural gas wells in the United States in 2009, the latest year for which government statistics are available.

CONSOL Energy s gas operations are primarily in the eastern United States. We believe that the gas market is highly fragmented and not dominated by any single producer. We believe that several of our competitors have devoted far greater resources than we have to gas exploration and development. We believe that competition within our market is based primarily on gas commodity trading fundamentals and pipeline transportation availability to the various markets.

Continued demand for CONSOL Energy s natural gas and the prices that CONSOL Energy obtains are affected by demand for electricity, environmental and government regulation, technological developments and the availability and price of competing alternative fuel supplies.

Power Generation

Through a joint venture with Allegheny Energy Supply Company, LLC, an affiliate of one of our largest coal customers, CONSOL Energy owns a 50% interest in an 88-megawatt, gas-fired electric generating facility. This facility is used for meeting peak load demands for electricity. The facility is located in southwest Virginia and uses coalbed methane gas that we produce. Because it is a peaking power facility, it does not operate at all times of the year, but the facility does provide a potential sales outlet for our gas of up to 22 million cubic feet per day.

Other Operations

CONSOL Energy provides other services both to our own operations and to others. These include land services, industrial supply services, terminal services (including break bulk, general cargo and warehouse services) and river and dock services.

Land Resources

CONSOL Energy is developing property assets previously used to support our coal operations or property assets currently not utilized. CONSOL Energy expects to increase the value of our property assets by:

- developing surface properties for commercial uses other than coal mining or gas development when the location of the property is suitable;
- deriving value from surface properties and right-of-ways in the development of gathering pipelines built for CONSOL Energy or for third parties;
- deriving royalty income from coal, oil and gas reserves CONSOL Energy owns but does not intend to develop;
- deriving income from the sustainable harvesting of timber on land CONSOL Energy owns; and
- deriving income from the rental of surface property for agricultural and non-agricultural uses.

CONSOL Energy s objective is to improve the return on these assets without detracting from our core businesses and without significant additional capital investment.

Industrial Supply Services

Fairmont Supply Company, a CONSOL Energy subsidiary, is a general-line distributor of mining, drilling, and industrial supplies in the United States. Fairmont Supply has 33 customer service centers nationwide.

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Fairmont Supply also provides integrated supply procurement and management services. Integrated supply procurement is a materials management strategy that utilizes a single, full-line distribution to minimize total cost in the maintenance, repair and operating supply chain.

Fairmont Supply provides mine and drilling supplies to CONSOL Energy s mining and gas operations. Approximately 47% of Fairmont Supply s sales in 2010 were made to CONSOL Energy s coal and gas divisions.

Fairmont Supply Company s subsidiary, Piping and Equipment Inc., is a specialty distributor of pipe, valve and fittings. Piping and Equipment has ten locations in Florida, Alabama, Louisiana and Texas. Fairmont Supply Company s other subsidiary, North Penn Pipe & Supply, LLC has locations in Warren and Troy, Pennsylvania, and distributes oil and gas field products, primarily tubular goods to the Northern Appalachia basin.

Terminal Services

In 2010, approximately 11.2 million tons of coal were shipped through CONSOL Energy s subsidiary, CNX Marine Terminal Inc. s, exporting terminal in the Port of Baltimore. Approximately 34% of the tonnage shipped was produced by CONSOL Energy coal mines. The terminal can either store coal or load coal directly into vessels from rail cars. It is also one of the few terminals in the United States served by two railroads, Norfolk Southern Corporation and CSX Transportation Inc.

River and Dock Services

CONSOL Energy s river operations, located in Monessen, Pennsylvania, transport coal from our mines, coal from other mines and non-coal commodities from river loadout facilities located primarily along the Monongahela and Ohio Rivers in northern West Virginia and southwestern Pennsylvania. Products are delivered to customers along the Monongahela, Ohio, Kanawha and Allegheny rivers. At December 31, 2010, we operated 22 towboats, 5 harbor boats and 620 barges. In 2010, our river vessels transported a total of 18.6 million tons of coal and other commodities, including 6.3 million tons of coal produced by CONSOL Energy mines.

CONSOL Energy provides dock services for our mines as well as for third parties at our Alicia Dock, located on the Monongahela River in Fayette County, Pennsylvania. CONSOL Energy transfers coal from rail cars to barges for customers that receive coal on the river system.

Employee and Labor Relations

At December 31, 2010, CONSOL Energy had 8,630 employees, approximately 34% of whom were represented by the United Mine Workers of America (UMWA). A five-year labor agreement commenced January 1, 2007. This agreement expires December 31, 2011 and provides for a 20% across-the-board wage increase over its duration. Wages increased $0.50 per hour in 2010 and will increase another $0.50 per hour in 2011. Other terms of the agreement require additional contributions to be made into the employee benefit funds. Full health-care benefits for active and retired members and their dependents continued with no increase in co-payments. Newly employed inexperienced employees represented by the UMWA, hired after January 1, 2007 will not be eligible to receive retiree health care benefits. In lieu of these benefits, these employees will receive a defined contribution benefit of $1 per each hour worked.

Laws and Regulations

The mining and gas industries are subject to regulation by federal, state and local authorities on matters such as the discharge of materials into the environment, permitting and other licensing requirements, reclamation and restoration of properties after mining or gas operations are completed, management of materials generated by mining and gas operations, surface subsidence from underground mining, water discharge effluent limits, water appropriation, air quality standards, protection of wetlands, endangered plant and wildlife protection, limitations

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on land use, storage of petroleum products and substances that are regarded as hazardous under applicable laws, management of electrical equipment containing polychlorinated biphenyls (PCBs), legislatively mandated benefits for current and retired coal miners, and employee health and safety. In addition, the electric power generation industry is subject to extensive regulation regarding the environmental impact of its power generation activities, which could affect demand for CONSOL Energy s coal and gas products. The possibility exists that new legislation or regulations may be adopted which would have a significant impact on CONSOL Energy s mining or gas operations or our customers ability to use coal or gas and may require CONSOL Energy or our customers to change their operations significantly or incur substantial costs.

Numerous governmental permits and approvals are required for mining and gas operations. Regulations provide that a mining permit or modification can be delayed, refused or revoked if an officer, director or a stockholder with a 10% or greater interest in the entity is affiliated with or is in a position to control another entity that has outstanding permit violations. Thus, all mining operations of CONSOL Energy entities must be maintained in compliance to avoid delay in issuance of necessary mining permits. CONSOL Energy is, or may be, required to prepare and present to federal, state or local authorities data and/or analyses pertaining to the effect or impact that any proposed exploration for or production of coal or gas may have upon the environment, the public and employee health and safety. All requirements imposed by such authorities may be costly and time-consuming and may delay commencement or continuation of exploration or production operations. Accordingly, the permits we need for our mining and gas operations may not be issued, or, if issued, may not be issued in a timely fashion. Permits we need may involve requirements that may be changed or interpreted in a manner which restricts our ability to conduct our mining and gas operations or to do so profitably. Future legislation and administrative regulations may increasingly emphasize the protection of the environment and employee health and safety. As a consequence, the activities of CONSOL Energy may be more closely regulated. Such legislation and regulations, as well as future interpretations of existing laws, may require substantial increases in equipment and operating costs to CONSOL Energy and delays, interruptions or a termination of operations, the extent of which cannot be predicted.

While it is not possible to quantify the expenditures we incur to maintain compliance with all applicable federal and state laws, those costs have been and are expected to continue to be significant. Compliance with these laws has substantially increased the cost of mining and gas production for all domestic coal and gas producers. We post surety performance bonds or letters of credit pursuant to federal and state mining laws and regulations for the estimated costs of reclamation and mine closing, often including the cost of treating mine water discharge when necessary. We also post performance bonds or letters of credit pursuant to state oil and gas laws and regulations to guarantee reclamation of gas well sites and plugging of gas wells. We endeavor to conduct our mining and gas operations in compliance with all applicable federal, state and local laws and regulations. However, because of extensive and comprehensive regulatory requirements, violations during mining and gas operations occur from time to time. CONSOL Energy made capital expenditures for environmental control facilities of approximately $39.9 million, $50.4 million and $10.6 million in the years ended December 31, 2010, 2009 and 2008, respectively. The capital expenditures for environmental control facilities increased in 2009 primarily due to starting construction of an advanced water processing system at the Buchanan Mine. Construction of this facility was completed in 2010. CONSOL Energy expects to have capital expenditures of $62.4 million in 2011 for environmental control facilities.

Mine Health and Safety Laws

Legislative and regulatory changes have required us to purchase additional safety equipment, construct stronger seals to isolate mined out areas, and engage in additional training. We have also experienced more aggressive inspection protocols resulting in the issuance of more citations and with new regulations the amount of civil penalties have increased.

The actions taken thus far by federal and state governments include requiring:

- the caching of additional supplies of self-contained self rescuer (SCSR) devices underground;

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the purchase and installation of electronic communication and personal tracking devices underground;

the placement of refuge chambers, which are structures designed to provide refuge for groups of miners during a mine emergency when evacuation from the mine is not possible, which will provide breathable air for 96 hours;

the replacement of existing seals in worked-out areas of mines with stronger seals;

the purchase of new fire resistant conveyor belting underground;

additional training and testing that creates the need to hire additional employees; and

more stringent rock dusting requirements.

In addition, on October 14, 2010, the Mine Safety and Health Administration (MSHA) published a proposed rule to reduce the permissible concentration of respirable dust in underground coal mines from the current standard of 2 milligram per cubic meter of air to one milligram per cubic meter. MSHA is also likely to adopt new safety standards for proximity protection for miners that will require certain underground mining equipment to be equipped with devices that will shut the equipment down if a person is too close to the equipment to avoid injuries where individuals are caught between equipment and blocks of unmined coal.

Occupational Safety and Health Act

Our gas operations are subject to regulation under the federal Occupational Safety and Health Act (OSHA) and comparable state laws in some states, all of which regulate health and safety of employees at our gas operations. Also, OSHA s hazardous communication standard requires that information be maintained about hazardous materials used or produced by our gas operations and that this information be provided to employees, state and local governments and the public.

Black Lung Legislation

Under federal black lung benefits legislation, each coal mine operator is required to make payments of black lung benefits or contributions to:

current and former coal miners totally disabled from black lung disease;

certain survivors of a miner who dies from black lung disease or pneumoconiosis; and

a trust fund for the payment of benefits and medical expenses to claimants whose last mine employment was before January 1, 1970, where no responsible coal mine operator has been identified for claims (where a miner s last coal employment was after December 31, 1969), or where the responsible coal mine operator has defaulted on the payment of such benefits. The trust fund is funded by an excise tax on U.S. production of up to $1.10 per ton for deep mined coal and up to $0.55 per ton for surface-mined coal, neither amount to exceed 4.4% of the gross sales price.

The Patient Protection and Affordable Care Act (PPACA), which was implemented in 2010, made two changes to the Federal Black Lung Benefits Act. First, it provided changes to the legal criteria used to assess and award claims by creating a legal presumption that miners are entitled to benefits if they have worked at least 15 years in coal mines and suffer from totally disabling lung disease. A coal company would have to prove that a miner did not have black lung or that the disease was not caused by the miner s work. Second, it changed the law so black lung benefits being received by miners automatically go to their dependent survivors, regardless of the cause of the miner s death. The impact of these law changes increased CONSOL Energy s pneumoconiosis liability by approximately $46 million during the year ended December 31, 2010.

In addition to the federal legislation, we are also liable under various state statutes for black lung claims.

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Retiree Health Benefits Legislation

The Coal Industry Retiree Health Benefit Act of 1992 (the Act) established the Combined Benefit Fund (the Combined Fund). The Combined Fund provides medical and death benefits for all beneficiaries including orphan retirees of the former United Mine Workers of America (UMWA) Benefit Trusts who were actually receiving benefits as of July 20, 1992. The Act also created a second benefit fund for UMWA retirees, the 1992 Benefit Plan. The 1992 Benefit Plan principally provides medical and death benefits to orphan UMWA-represented members eligible for retirement on February 1, 1993, and who actually retired between July 20, 1992 and September 30, 1994. The Act provides for the assignment of beneficiaries to former signatory employers or related companies and the allocation of responsibility for unassigned beneficiaries (referred to as orphans) to the assigned operators. The task of calculating the annual per beneficiary premium that assigned operators are obligated to pay to the Combined Fund is the responsibility of the Commissioner of Social Security.

The UMWA 1993 Benefit Plan is a defined contribution plan that was created as the result of negotiations for the National Bituminous Coal Wage Agreement (NBCWA) of 1993. This plan provides health care benefits to orphan UMWA retirees who are not eligible to participate in the Combined Fund, the 1992 Benefit Fund, or whose last employer signed the 1993 NBCWA or a later NBCWA, and who subsequently goes out of business.

The Act requires some of our signatory subsidiaries to make premium payments to the Combined Fund and to the 1992 Benefit Plan for the cost of our retirees and orphan retirees in those plans. In addition, the NBCWA of 2007 requires our signatory subsidiaries to make specified payments to the 1993 Benefit Plan through 2011. The Tax Relief and Health Care Act of 2006 (the 2006 Act) provides additional federal funding for these orphan costs by authorizing general fund revenues and expanding transfers of interest from the Abandoned Mine Land (AML) trust fund. The additional federal funding, depending upon its magnitude and the amount of orphan benefits payable, should cover the orphan premium payments due under the Combined Fund as well as, after a phase-in period, the orphan premium payments due under the 1992 Benefit Plan. Federal contributions were 75% in 2010. Federal contributions are expected to be 100% after 2010. In addition, federal contributions are also to be phased-in over the same period with respect to the costs for those orphan retirees as of December 31, 2006 under the 1993 Benefit Plan. Under the 2006 Act, these general fund contributions to the Combined Fund, the 1992 Benefit Plan and the 1993 Benefit Plan and certain AML payments to the states and Indian tribes are collectively limited by an aggregate annual cap of $490 million. These federal contributions do not apply to our subsidiaries assigned retired miners, and therefore our subsidiaries will continue to make premium payments for our assigned retired miners who receive benefits from the Combined Fund, the 1992 Benefit Plan and for certain beneficiaries of the 1993 Benefit Plan. In addition, our subsidiaries remain responsible for making orphan premium payments to the Combined Fund and 1992 Benefit Plan to the extent that the federal contributions are not sufficient to cover the benefits.

Pension Protection Act

The Pension Protection Act of 2006 (the Pension Act) has simplified and transformed rules governing the funding of defined benefit plans, accelerated funding obligations of employers, made permanent certain provisions of the Economic Growth and Tax Relief Reconciliation Act of 2001 (EGTRRA), made permanent the diversification rights and investment education provisions for plan participants and encourages automatic enrollment in defined contribution 401(k) plans. In general, most provisions of the Pension Act of 2006 are in effect for plan years beginning on or after December 31, 2008. Plans generally are required to set a funding target of 100% of the present value of accrued benefits and sponsors are required to amortize unfunded liabilities over a seven year period. The Pension Act includes a funding target phase-in provision consisting of a 96% funding target in 2010 and 100% thereafter. Plans with a funded ratio of less than 80%, or less than 70% using special assumptions, will be deemed to be at risk and will be subject to additional funding requirements. The 2010 plan year funding ratio was 96%. The funding ratio is subject to year over year volatility and Internal Revenue Service s calculation guidelines.

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Environmental Laws

CONSOL Energy is subject to various federal environmental laws, including:

- the Surface Mining Control and Reclamation Act of 1977,
- the Clean Air Act,
- the Clean Water Act,
- the Endangered Species Act,
- the Resource Conservation and Recovery Act,
- the Comprehensive Environmental Response, Compensation and Liability Act,
- the Toxic Substances Control Act, and
- the Emergency Planning and Community Right to Know Act,

as administered and enforced by United States Environmental Protection Agency (EPA) and/or authorized federal or state agencies, as well as state laws of similar scope, and other state environmental and conservation laws in each state in which CONSOL Energy operates.

These environmental laws require reporting, permitting and/or approval of many aspects of coal mining and gas operations. Both federal and state inspectors regularly visit mines and other facilities to ensure compliance. CONSOL Energy has ongoing compliance and permitting programs designed to ensure compliance with such environmental laws.

Given the retroactive nature of certain environmental laws, CONSOL Energy has incurred, and may in the future incur liabilities in connection with properties and facilities currently or previously owned or operated. Liabilities above may be increased for sites to which CONSOL Energy or our subsidiaries sent waste materials.

Surface Mining Control and Reclamation Act

The Surface Mining Control and Reclamation Act (SMCRA) establishes minimum national operational, reclamation and closure standards for all surface mines as well as most aspects of deep mines. SMCRA requires that comprehensive environmental protection and reclamation standards be met during the course of and following completion of mining activities. Permits for all mining operations must be obtained from the Federal Office of Surface Mining Reclamation and Enforcement (OSM) or, where state regulatory agencies have adopted federally approved state programs under SMCRA, the appropriate state regulatory authority. States that operate federally approved state programs may impose standards which are more stringent than the requirements of SMCRA and OSM s regulations and in many instances have done so. All states in which CONSOL Energy s active mining operations are located have achieved primary jurisdiction for enforcement of SMCRA through approved state programs.

SMCRA permit provisions include requirements for coal exploration; baseline environmental data collection and analysis; mine plan development; topsoil removal, storage and replacement; selective handling of overburden materials; mine pit backfilling and grading; protection of the hydrologic balance; subsidence control for underground mines; refuse disposal plans; surface drainage control; mine drainage and mine discharge control and treatment; and site reclamation. Once a permit application is prepared and submitted to the regulatory agency, it goes through an administrative completeness review and a separate technical review. Public notice of the proposed permit application is given in a local newspaper followed by a public comment period before a permit can be issued. Some mining permits take over a year to prepare, depending on the size and complexity of the mine and can take six months to three years to be issued. Regulatory authorities have considerable discretion in the timing of the permit issuance. The public has the right to comment on and otherwise participate in the permitting process, including through administrative appeals of permits and possibly further appeals in the

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courts. The mine operator must submit a bond or otherwise secure the performance of reclamation obligations, including, as deemed appropriate by the regulatory authority, a bond sufficient to cover the costs of long-term treatment of mine drainage discharges from closed facilities or ones from which a post-mining discharge is anticipated. The earliest a reclamation bond can be fully released is five years after reclamation has been completed, however, partial releases may be obtained as certain stages of reclamation are completed. All states impose on mine operators the responsibility for repairing or compensating for damage occurring on the surface as a result of mine subsidence, a possible consequence of longwall or other methods of underground mining. All states also impose an obligation on surface mining operations to replace domestic, agricultural or industrial water supplies adversely affected by such operations. In addition, SMCRA imposes a reclamation fee on all current mining operations, the proceeds of which are deposited in the Abandoned Mine Reclamation Fund (AML Fund), which is used to restore unreclaimed and abandoned mine lands mined before 1977. The current per ton fee is $0.315 per ton for surface mined coal and $0.135 per ton for underground mined coal. From October 1, 2012 through September 30, 2021, the fees will be $0.28 per ton for surface mined coal and $0.12 per ton for underground mined coal.

In Pennsylvania, where CONSOL Energy operates three longwall mines, approximately $21.8 million and $30.3 million of expenses were incurred during the years ended December 31, 2010 and 2009, respectively, to mitigate and repair impacts on streams from subsidence. With respect to subsidence impacts to streams, the regulatory requirement to minimize impacts to the hydrologic balance could cause CONSOL Energy to change mine plans, to incur significant costs, and potentially even shut down mines in order to meet compliance requirements. We currently estimate expenses related to subsidence of streams in Pennsylvania will be approximately $24.2 million for the year ended December 31, 2011.

Clean Air Act and Related Regulations

The federal Clean Air Act and similar state laws and regulations which regulate emissions into the air, affect coal mining, coal handling and processing, and gas processing operations primarily through permitting and/or emissions control requirements. For example, regulations relating to fugitive dust and coal combustion emissions could restrict CONSOL Energy s ability to develop new mines or require CONSOL Energy to modify our operations. National Ambient Air Quality Standards (NAAQS) for particulate matter resulted in some areas of the country being classified as non-attainment for fine particulate matter. Because thermal dryers located at coal preparation plants burn coal and emit particulate matter, CONSOL Energy s mining operations are likely to be directly affected where the NAAQS are implemented by the states.

The Clean Air Act also indirectly affects coal mining operations by extensively regulating the air emissions of the coal fired electric power generating plants operated by our customers. Coal contains impurities, such as sulfur, mercury and other constituents, many of which are released into the air when coal is burned. Carbon dioxide, a greenhouse gas, is also emitted when coal is burned. Environmental regulations governing emissions from coal-fired electric generating plants could affect demand for coal as a fuel source and affect the volume of our sales. For example, the federal Clean Air Act places limits on sulfur dioxide, nitrogen dioxide, and mercury emissions from electric power plants.

In October 1998, the EPA finalized a rule requiring a number of eastern U.S. states to make substantial reductions in nitrogen oxide emissions by June 1, 2004 (the NOX SIP call). Further sulfur dioxide and nitrogen oxide emission reductions were adopted by regulations called the Clean Air Interstate Rules (CAIR), which were promulgated by the EPA in 2005. In July and December 2008, the U.S. Court of Appeals for the District of Columbia remanded the CAIR regulations to the EPA but did not vacate the regulations. The regulations were not vacated because many states were already implementing them and some coal fired electric generating facilities were being equipped with scrubbers in order to comply with the CAIR requirements. In August 2010, the EPA published in the Federal Register the proposed Clean Air Transport Rule (the Transport Rule). The Transport Rule is intended to replace CAIR. The Transport Rule will allow minimal or no interstate trading. This will likely make compliance more expensive. The EPA s schedule is to finalize the Transport Rule by July 2011. The first phase of the Transport Rule emission reductions will go into effect in 2012.

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The installation of additional control measures to achieve regulatory emission reductions makes it more costly to operate coal-fired power plants and could make coal a less attractive fuel. In order to meet the proposed new limits for sulfur dioxide emissions from electric power plants, many coal users need to install scrubbers, use sulfur dioxide emission allowances (some of which they may purchase), blend high sulfur coal with low sulfur coal or switch to low sulfur coal or other fuels. More strict emission limits mean few coals can be burned without the installation of supplemental environmental control technology in the form of scrubbers. Many of our customers are in the process of installing scrubbers in response to the CAIR emissions requirements. We estimate that by 2012, more than half of the installed, coal-fired power plant capacity east of the Mississippi will be scrubbed. The increase in scrubbed capacity allows customers to consider purchasing more of our higher sulfur coals.

In 2005, the EPA finalized the Clean Air Mercury Rule (CAMR) which imposed caps on mercury emissions from coal-fired electric generating units. The first phase of the emission caps would have taken effect in 2010. In February 2008, the U.S. Court of Appeals for the D.C. Circuit vacated the CAMR. EPA is developing emission limits for mercury for coal fired electric generating facilities under Section 112 of the Clean Air Act, which requires the EPA to impose maximum achievable control technology (MACT) limits. The EPA intends to issue proposed MACT regulations for mercury in March 2011 and to issue final MACT regulations in November 2011. Various states have promulgated or are considering more stringent emission limits on mercury emissions from coal-fired electric generating units. Regulation of mercury emissions from coal-fired electric generating units could impact the market for coal.

A regional haze program initiated by the EPA to protect and to improve visibility at and around national parks, national wilderness areas and international parks may restrict the construction of new coal-fired power plants whose operation may impair visibility at and around federally protected areas and may require some existing coal-fired power plants to install additional control measures designed to limit haze-causing emissions. These requirements could limit the demand for coal in some locations.

The Clean Air Act and comparable state laws restrict the emission of air pollutants from compressor stations used in our gas operations. We may also be required to obtain pre-approval for construction or modification of certain facilities, to meet stringent air permit requirements, or to use specific equipment, technologies or best management practices to control emissions.

Also, numerous proposals have been made at the international, national, regional and state levels that are intended to limit or capture emissions of greenhouse gases, such as carbon dioxide and methane, and several states have adopted measures intended to reduce greenhouse gas loading in the atmosphere. Burning of coal and natural gas produce carbon dioxide. Also, natural gas and coalbed gas contain methane. If comprehensive legislation focusing on greenhouse gas (GHG) emissions is enacted by the United States or individual states, it may adversely affect the use of and demand for fossil fuels, particularly coal, as an energy source for electricity generation. In 2007, the U.S. Supreme Court held in *Massachusetts v. Environmental Protection Agency (EPA)*, that the EPA had authority to regulate GHGs under the Clean Air Act and a number of states have filed lawsuits seeking to force the EPA to adopt GHG regulations. In December 2009, the EPA made a determination that GHGs cause or contribute to air pollution and may reasonably be anticipated to endanger public health or welfare, which findings are prerequisites to the EPA regulating GHGs under the Clean Air Act. Although, efforts to enact greenhouse gas legislation have failed, the EPA is proceeding with greenhouse gas regulations. In September 2009, the EPA finalized the Mandatory Reporting of Greenhouse Gas Rule. The current version of this rule requires reporting of emissions from coal mines and gas wells and associated facilities for 2011 emissions. In December 2010, the EPA announced a proposed schedule for establishing greenhouse gas emission limits for fossil fuel fired electric generating facilities (proposed regulations by July 2011 and final regulations by May 2012.) Such regulations could significantly increase the cost of generation of electricity at coal fired facilities and could make competing forms of electricity generation more competitive.

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Clean Water Act

The federal Clean Water Act and corresponding state laws affect coal and gas operations by imposing restrictions on discharges into regulated surface waters. Permits requiring regular monitoring and compliance with effluent limitations and reporting requirements govern the discharge of pollutants into regulated waters. The Clean Water Act and corresponding state laws include requirements for: improvement of designated impaired waters (not meeting state water quality standards) through the use of effluent limitations established so that all discharges to the impaired stream do not exceed Total Maximum Daily Load (TMDL) levels of the pollutants causing the impairment; anti-degradation regulations which protect state designated high quality/exceptional use streams by restricting or prohibiting discharges which result in degradation; requirements to treat discharges from coal mining properties for non-traditional pollutants, such as chlorides, selenium and dissolved solids; and protecting streams, wetlands, other regulated water sources and associated riparian lands from surface mining and/or the surface impacts of underground mining; and the requirements to obtain permits for the discharge of produced wastes and other oil and gas wastes, or to dispose of such substances at approved disposal facilities. These requirements may cause CONSOL Energy to incur significant additional costs that could adversely affect our operating results, financial condition and cash flows.

Permits for discharges of fill material into streams in connection with mining operations are issued by the Army Corps of Engineers (the COE). The COE is empowered to issue nationwide permits for specific categories of filing activity that are determined to have minimal environmental adverse effects in order to save the cost and time of issuing individual permits under Section 404 of the Clean Water Act. Individual permits are required for activities determined to have more significant impacts to the waters of the United States. Since 2003, environmental groups have pursued litigation primarily in West Virginia and Kentucky challenging the validity of Nationwide Permit 21 and various individual permits authorizing valley fills associated with surface coal mining operations (primarily mountain top removal operations). This litigation has resulted in delays in obtaining these permits and has increased permitting costs. The most recent major decision in this line of litigation is the opinion of the United States Court of Appeals for the Fourth Circuit in *Ohio Valley Environmental Council v. Aracoma Coal Company,* 556 F.3d 177 (2009) (*Aracoma)*, issued on February 13, 2009. *Aracoma* appeared to be a major victory for the coal industry because the Court rejected all of the substantive challenges to the Section 404 permits involved in the case primarily by deferring to the expertise of the COE in review of the permit applications. The effect of the *Aracoma* decision was quickly nullified by several EPA initiatives relating to Section 404 permits and other permits and approvals required for coal mining operations. First, in early 2009, the EPA began to comment on Section 404 permit applications pending before the COE raising many of the same issues decided in favor of the coal industry in *Aracoma.* Many of the EPA s comment letters were submitted long after the end of the EPA s comment period based on what the EPA contended was new information on the impacts of valley fills on stream water quality immediately downstream of valley fills. However, the comment letters addressed many issues beyond the new information on alleged water quality impacts, such as, minimization of the size and number of valley fills, cumulative impacts of the operation on the watershed, and the types and extent of mitigation. These comment letters practically resulted in a moratorium on the issuance of Section 404 permits for valley fills for coal surface mines. A second initiative of the EPA is enhanced review of any permit for a coal mining activity that requires both a SMCRA permit and a Section 404 permit in the states of Kentucky, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia (designated as Appalachian Surface Coal Mining). This initiative resulted in a joint Memorandum of Understanding (MOU) among the COE, the EPA and the Department of Interior (OSM). The enhanced review under the MOU has continued the delay in COE action on pending Section 404 permit applications. A third initiative is to take a more active role in its review of NPDES permit applications for coal mining operations. A fourth initiative is EPA guidance to the states that instream specific conductance levels exceeding 500 microSiemens per centimeter is presumptive evidence that state narrative water quality standards which generally prohibit discharges harmful to aquatic life would be violated requiring the states to establish permit effluent limits to maintain instream specific conductance below 500 microSiemens per centimeter. Additionally, EPA s initiatives are being supported by environmental groups. Two citizen groups recently filed a Clean Water Act citizen suit against a CONSOL Energy subsidiary alleging that discharges from a surface mine in West Virginia violate state water quality standards in part because the specific conductance in the receiving stream exceeds the EPA benchmark of 500 microSiemens per centimeter. All of these initiatives have resulted in delays in the review and issuance of permits for surface coal mining operations, including applications for surface facilities for underground mines, such as applications for coal refuse disposal areas. So far, CONSOL Energy subsidiaries have been able to continue operating their existing mines. Also, in 2009 one subsidiary was able to obtain a Section 404 permit for a new surface mine in southern West Virginia. However, the new permit contains EPA mandated environmental protection conditions. The EPA s enhanced scrutiny initiatives have been challenged by the National Mining Association (NMA). On January 14, 2011, the U. S. District Court for the District of Columbia denied the EPA s motion to dismiss the NMA s complaint and also denied the NMA s motion for a preliminary injunction of the EPA s enhanced scrutiny initiatives. Although the NMA s motion for a preliminary injunction was denied, the opinion contains holdings suggesting that the court may rule in favor of the NMA on the merits of the case. Unless the NMA is successful in its challenge of the EPA s enhanced scrutiny of permit applications, we anticipate that it will continue to take longer to obtain permits and the costs of obtaining permits and compliance with permit conditions will increase significantly. These requirements may cause CONSOL Energy to incur additional costs that could adversely affect our operating results, financial condition and cash flows.

In December 2010, the Pennsylvania Department of Environmental Protection designated portions of the Monongahela River as impaired (not meeting state water quality standards) for sulfates in Pennsylvania s biennial Integrated Water Quality Monitoring and Assessment Report to the EPA. The Clean Water act and corresponding state laws include requirements for improvement of designated impaired waters (not meeting state water quality standards) through the use of effluent limitations established so that all discharge to the impaired stream do not exceed the Total Maximum Daily Load (TMDL) levels of the pollutants causing the impairment. A TMDL accounts for existing loading of the pollutant (sulfates in this case) and sets a cumulative pollution load for the stream so as to prevent violations of state water quality standards. TMDL s are used to set best management practices and set permit discharge limits. TMDL-based discharge limits are frequently more stringent than existing permit limits or often result in limits for pollutants that were not previously regulated. CONSOL Energy has one active underground mine and several closed mines in Pennsylvania that discharge into the Monongahela River. All of these operations could be subject to new effluent limits for sulfates that may result in the need to construct and operate expensive advanced water treatment facilities.

The EPA has announced that it will conduct a comprehensive study of the potential adverse impact that hydraulic fracturing may have on water quality and public health. Hydraulic fracturing is a way of producing gas from tight rock formations such as the Barnett and Marcellus shales. The EPA plans to initiate the study in January 2011 and have the initial study results available by late 2012. It is too early to predict what actions, if any, will result from the study.

Endangered Species Act

The Federal Endangered Species Act (ESA) and similar state laws protect species threatened with extinction. Protection of endangered species may affect our ability to obtain permits for mining and gas operations, may delay issuance of mining permits, or may cause us to modify mining plans or develop and implement species-specific protection and enhancement plans to avoid or minimize impacts to endangered species or their habitats. A number of species indigenous to the areas where we operate are protected under the ESA. Based on the species that have been identified and the current application of applicable laws and regulations, we do not believe that there are any species protected under the ESA or state laws that would materially and adversely affect our ability to mine coal or produce gas from our properties.

Comprehensive Environmental Response, Compensation and Liability Act (Superfund)

The Comprehensive Environmental Response, Compensation and Liability Act (Superfund) and similar state laws create liabilities for the investigation and remediation of releases of hazardous substances into the environment and for damages to natural resources. We could incur liability under CERCLA relative to our coal or gas operations. Our current and former coal mining operations incur, and will continue to incur, expenditures associated with the investigation and remediation of facilities and environmental conditions, including underground storage tanks, solid and hazardous waste disposal and other matters under Superfund and similar state environmental laws. We also must comply with reporting requirements under the Emergency Planning and Community Right-to-Know Act and the Toxic Substances Control Act.

From time to time, we have been the subject of administrative proceedings, litigation and investigations relating to sites that have released hazardous substances. We have been in the past and currently are named as a potentially responsible party at Superfund sites. We may become involved in future proceedings, litigation or investigations and incur liabilities that could be materially adverse to us.

Resource Conservation and Recovery Act

The federal Resource Conservation and Recovery Act (RCRA) and corresponding state laws and regulations affect coal mining and gas operations by imposing requirements for the treatment, storage and disposal of hazardous wastes. Facilities at which hazardous wastes have been treated, stored or disposed are subject to corrective action orders issued by the EPA which could adversely affect our results, financial condition and cash flows.

RCRA exempted fossil fuel combustion wastes (coal combustion wastes) from hazardous waste regulation until the EPA completed a report to Congress and made a determination on whether the wastes should be regulated as hazardous waste. In May 2000, the EPA concluded that coal combustion wastes do not warrant regulation as hazardous under RCRA resulting in coal combustion wastes remaining exempt from hazardous waste regulation. However, the EPA determined that national non-hazardous waste regulations under RCRA are needed for coal combustion wastes disposed in surface impoundments and landfills and used as mine-fill, and the Office of Surface Mining is currently developing these regulations. The agency also concluded that beneficial uses of these wastes, other than for mine-filling, pose no significant risk and no additional national regulations are needed. Most state hazardous waste laws also exempt coal combustion waste, and instead treat it as either a solid waste or a special waste. In response to the Tennessee Valley Authority coal ash spill in December 2008, the EPA initiated a fast-track regulatory process in which it is considering three possible regulatory scenarios for coal combustion wastes: regulation as a non-hazardous waste under Subtitle D of RCRA, regulation as a hazardous waste under Subtitle C, or a hybrid Subtitle C/D approach. The proposed Coal Combustion Residuals Rule was published in June 2010. The public comment period ended on November 19, 2010. Industry and state regulatory agencies are trying to convince the EPA that the states are adequately regulating the handling and disposal of coal combustion wastes. The loss of the hazardous waste exemption for coal combustion waste, or the adoption of new regulations for disposing of coal combustion waste which impose significant additional costs, could adversely affect the demand for coal for electricity generation.

Federal Coal Leasing Amendments Act

Mining operations on federal lands in the western United States are affected by regulations of the United States Department of the Interior. The Federal Coal Leasing Amendments Act of 1976 amended the Mineral Lands Leasing Act of 1920 which authorized the leasing of federal coal lands for coal mining. The Federal Coal Leasing Amendments Act increased the royalties payable to the United States Government for federal coal leases and required diligent development and continuous operations of leased reserves within a specified period of time. Subtitle D of the Energy Policy Act of 2005 (Pub. L. 109-58) contained the Coal Leasing Amendments Act of 2005, which includes provisions designed to facilitate efficient and economic development of federal coal leases. The United States Department of the Interior has stated that it intends to promulgate new regulations and implement these 2005 amendments. Regulations adopted by the United States Department of the Interior to implement such legislation could affect coal mining by CONSOL Energy from federal coal leases.

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Federal Regulation of the Sale and Transportation of Gas

Various aspects of our gas operations are regulated by agencies of the federal government. The Federal Energy Regulatory Commission regulates the transportation and sale of natural gas in interstate commerce pursuant to the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. While first sales by producers of natural gas, and all sales of condensate and natural gas liquids can be made currently at uncontrolled market prices, Congress could reenact price controls in the future. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all Natural Gas Act and Natural Gas Policy Act price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993.

Regulations and orders set forth by the Federal Energy Regulatory Commission also impact our gas business to a certain degree. Although the Federal Energy Regulatory Commission does not directly regulate our gas production activities, the Federal Energy Regulatory Commission has stated that it intends for certain of its orders to foster increased competition within all phases of the natural gas industry. Additionally, the Federal Energy Regulatory Commission continues to review its transportation regulations, including whether to allocate all short-term capacity on the basis of competitive auctions and whether changes to its long-term transportation policies may also be appropriate to avoid a market bias toward short-term contracts. Additional Federal Energy Regulatory Commission orders have been adopted based on this review with the goal of increasing competition for natural gas markets and transportation.

The Federal Energy Regulatory Commission has also issued numerous orders confirming the sale and abandonment of natural gas gathering facilities previously owned by interstate pipelines and acknowledging that if the Federal Energy Regulatory Commission does not have jurisdiction over services provided by these facilities, then such facilities and services may be subject to regulation by state authorities in accordance with state law. In addition, the Federal Energy Regulatory Commission s approval of transfers of previously-regulated gathering systems to independent or pipeline affiliated gathering companies that are not subject to Federal Energy Regulatory Commission regulation may affect competition for gathering or natural gas marketing services in areas served by those systems and thus may affect both the costs and the nature of gathering services that will be available to interested producers or shippers in the future.

We own certain natural gas pipeline facilities that we believe meet the traditional tests which the Federal Energy Regulatory Commission has used to establish a pipeline s status as a gatherer not subject to the Federal Energy Regulatory Commission jurisdiction.

Additional proposals and proceedings that might affect the gas industry may be pending before Congress, the Federal Energy Regulatory Commission, the Minerals Management Service, state commissions and the courts. We cannot predict when or whether any such proposals may become effective. In the past, the natural gas industry has been heavily regulated. There is no assurance that the regulatory approach currently pursued by various agencies will continue indefinitely. Notwithstanding the foregoing, we do not anticipate that compliance with existing federal, state and local laws, rules and regulations will have a significantly adverse effect upon the capital expenditures, earnings or competitive position of CONSOL Energy or its subsidiaries. No material portion of our business is subject to renegotiation of profits or termination of contracts or subcontracts at the election of the federal government.

State Regulation of Gas Operations

Our gas operations are also subject to regulation at the state and in some cases, county, municipal and local governmental levels. Such regulation includes requiring permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells, the disposal of fluids used in connection with operations, and gas operations producing coalbed methane in relation to active mining. Our operations are also subject to various conservation laws and regulations. These include regulations that affect the size of drilling and spacing units or proration units, the density of wells which may be drilled and the unitization or pooling of gas properties. In addition, state conservation laws establish maximum rates of production from gas wells, generally prohibit the venting or flaring of gas and impose certain requirements regarding the ratability of production. A number of states have either enacted new laws or may be considering the adequacy of existing laws affecting gathering rates and/or services. Other state regulation of gathering facilities generally includes various safety, environmental and in some circumstances, nondiscriminatory take requirements, but does not generally entail rate regulation. Thus, natural gas gathering may receive greater regulatory scrutiny of state agencies in the future. Our gathering operations could be adversely affected should they be subject in the future to increased state regulation of rates or services, although we do not believe that they would be affected by such regulation any differently than other natural gas producers or gatherers. However, these regulatory burdens may affect profitability, and we are unable to predict the future cost or impact of complying with such regulations.

Ownership of Mineral Rights

CONSOL Energy s past practice has been to acquire ownership or leasehold rights to our coal properties prior to conducting our coal mining operations. Given CONSOL Energy s long history as a coal producer we believe we have a well-developed ownership position relating to our coal holdings. Although CONSOL Energy generally attempts to obtain ownership or leasehold rights to CBM and/or conventional gas related to our coal holdings, our ownership position relating to these property estates is less developed. As is customary in the coal and gas industry, a summary review of the title to coal, CBM and other gas rights is made on properties at the time of the acquisition of the other rights in the properties. Prior to the commencement of gas drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect title defects on those properties; we are typically responsible for curing any title defects. We generally will not commence our drilling operations on a property until we have cured any material title defects on such property. We completed title work on substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the gas industry.

The following summary sets forth an analysis of provisions of Pennsylvania, Virginia and West Virginia law relating to the ownership of CBM. These summaries do not purport to be complete and are qualified in their entirety by reference to the provisions of applicable law and rights and the laws relating to traditional natural gas resources may differ materially from the rights related to CBM. These summaries are based on current law as of the date of this Annual Report on Form 10-K.

Pennsylvania

In Pennsylvania, CBM that remains inside the coal seam is generally the property of the owner of that coal seam where the gas is located. CBM can be sold in place or leased by the coal owner to another party such as a producer who then would have the right to extract the gas from the coal seam under the terms of the agreement with the coal owner. Once the gas migrates from the coal into other strata, the coal owner no longer has clear title to that migrated gas. As a result, in certain circumstances in Pennsylvania (*e.g*., in a gob or mine void), we may be required to obtain other property interests (beyond ownership or leasehold interest in the coal rights or CBM) in order to extract gas that is no longer located in the coal seam.

Virginia

The Virginia Supreme Court has stated that the grant of coal rights only does not include rights to CBM absent an express grant of CBM, natural gases, or minerals in general. The situation may be different if there is any expression in the severance deed indicating more than mere coal is conveyed. Virginia courts have also found that the owner of the CBM did not have the right to fracture the coal in order to retrieve the CBM and that the coal operator had the right to ventilate the CBM in the course of mining. In Virginia, we believe that we control the relevant property rights in order to capture gas from the vast majority of our producing properties.

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In addition, Virginia has established the Virginia Gas and Oil Board and a procedure for the development of CBM by an operator in those instances where the owner of the CBM has not leased it to the operator or in situations where there are conflicting claims of ownership of the CBM. The general practice is to force pool both the coal owner and the gas owner. In those instances, any royalties otherwise payable are paid into escrow and the burden then is upon the conflicting claimants to establish ownership by court action. The Virginia Gas and Oil Board does not make ownership decisions.

West Virginia

The West Virginia Supreme Court has held that in a conventional oil and gas lease executed prior to the inception of widespread public knowledge regarding CBM operations, the oil and gas lessee did not acquire the right to produce CBM. As of December 31, 2010, the West Virginia courts have not clarified who owns CBM in West Virginia. Therefore, the ownership of CBM is an open question in West Virginia.

West Virginia has enacted a law, the Coalbed Methane Wells and Units Act (the West Virginia Act), regulating the commercial recovery and marketing of CBM. Although the West Virginia Act does not specify who owns, or has the right to exploit, CBM in West Virginia and instead refers ownership disputes to judicial resolution, it contains provisions similar to Virginia s pooling law. Under the pooling provisions of the West Virginia Act, an applicant who proposes to drill can prosecute an administrative proceeding with the West Virginia Coalbed Methane Review Board to obtain authority to produce CBM from pooled acreage. Owners and claimants of CBM interests who have not consented to the drilling are afforded certain elective forms of participation in the drilling (*e.g.*, royalty or owner), but their consent is not required to obtain a pooling order authorizing the production of CBM by the operator within the boundaries of the drilling unit. The West Virginia Act also provides that, where title to subsurface minerals has been severed in such a way that title to coal and title to natural gas are vested in different persons, the operator of a CBM well permitted, drilled and completed under color of title to the CBM from either the coal seam owner or the natural gas owner has an affirmative defense to an action for willful trespass relating to the drilling and commercial production of CBM from that well.

We anticipate in future years to more actively explore for and develop Northern Appalachian CBM in West Virginia. As indicated, we may need or desire to acquire additional rights from other holders of real estate interests, including acquiring rights from other real estate interest holders if the law at that time continues to lack clarity on ownership rights to CBM in West Virginia. As we explore and develop this other acreage where we have coal rights, we expect, in accordance with our existing procedures, to have a title examination performed of the rights to CBM. If we believe we need to obtain additional rights from the holders of other real estate interests, we have developed a methodology as part of deciding the feasibility of developing a particular tract to evaluate the ability to locate and negotiate a royalty arrangement with those other holders or use pooling provisions under the West Virginia Act.

Other States

We have rights to extract CBM where we have coal rights in other states. The ownership of CBM in the Illinois Basin and certain other western basins may be uncertain or could belong to other holders of real estate interests and we may need to acquire additional rights from other holders of real estate interests to extract and produce CBM in these other states.

Available Information

CONSOL Energy maintains a website on the World Wide Web at *www.consolenergy.com*. CONSOL Energy makes available, free of charge, on this website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the 1934 Act), as soon as reasonably practicable after such reports are available, electronically filed with, or furnished to the SEC, and are also available at the SEC s website *www.sec.gov*.

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Executive Officers of the Registrant

Incorporated by reference into this Part I is the information set forth in Part III, Item 10 under the caption Directors and Executive Officers of CONSOL Energy (included herein pursuant to Item 401 (b) of Regulation S-K).

Item 1A. ***Risk Factors.***

Investment in our securities is subject to various risks, including risks and uncertainties inherent in our business. The following sets forth factors related to our business, operations, financial position or future financial performance or cash flows which could cause an investment in our securities to decline and result in a loss.

Deterioration in the economic conditions in any of the industries in which our customers operate, or sustained uncertainty in financial markets, may have adverse impacts on our business and financial condition that we currently cannot predict.

Economic conditions in a number of industries in which our customers operate, such as electric power generation and steel making, substantially deteriorated in recent years and reduced the demand for natural gas and coal. Although global industrial activity recovered in 2010 from 2009 levels, the continuation of the recovery, especially for industries in the United States and Europe, is uncertain. During recent years, financial markets in the United States, Europe and Asia also experienced unprecedented turmoil and upheaval. This was characterized by extreme volatility and declines in security prices, severely diminished liquidity and credit availability, inability to access capital markets, the bankruptcy, failure, collapse or sale of various financial institutions and an unprecedented level of intervention from the United States federal government and other governments. Although we cannot predict the impacts, renewed weakness in the economic conditions of any of the industries we serve or in the financial markets could materially adversely affect our business and financial condition. For example:

- demand for natural gas and electricity in the United States is impacted by industrial production, which if weakened would negatively impact the revenues, margins and profitability of our natural gas and steam coal business;

- demand for metallurgical coal hinges on steel demand in the United States and globally, which if weakened would negatively impact the revenues, margins and profitability of our metallurgical coal business;

- the tightening of credit or lack of credit availability to our customers could adversely affect our ability to collect our trade receivables and the amount of receivables eligible for sale pursuant to our accounts receivable securitization facility may decline;

- our ability to access the capital markets may be restricted at a time when we would like, or need, to raise capital for our business including for exploration and/or development of our coal or gas reserves; and

- our commodity hedging arrangements could become ineffective if our counterparties are unable to perform their obligations or seek bankruptcy protection.

A significant or extended decline in the prices CONSOL Energy receives for our coal and gas could adversely affect our operating results and cash flows.

Our financial results are significantly affected by the prices we receive for our coal and gas. Extended or substantial price declines for coal would adversely affect our operating results for future periods and our ability to generate cash flows necessary to improve productivity and expand operations. Prices of coal may fluctuate due to factors beyond our control such as overall domestic and global economic conditions; the consumption pattern of industrial consumers, electricity generators and residential users; increased utilization by the steel industry of electric arc furnaces or pulverized coal processes to make steel which do not use furnace coke, an intermediate

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product produced from metallurgical coal; technological advances affecting energy consumption; domestic and foreign government regulations; price and availability of alternative fuels; price of foreign imports; and weather conditions. Any adverse change in these factors could result in weaker demand and possibly lower prices for our coal production, which would reduce our revenues.

Gas prices are closely linked to supply of natural gas and consumption patterns in the United States of the electric power generation industry and certain industrial and residential patterns where gas is the principal fuel. Natural gas prices are very volatile, and even relatively modest drops in prices can significantly affect our financial results and impede growth. Changes in natural gas prices have a significant impact on the value of our reserves and on our cash flow. In the past we have used hedging transactions to reduce our exposure to market price volatility when we deemed it appropriate. If we choose not to engage in, or reduce our use of hedging arrangements in the future, we may be more adversely affected by changes in natural gas prices than our competitors who engage in hedging arrangements to a greater extent than we do. Prices for natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for natural gas, market uncertainty and a variety of additional factors that are beyond our control, such as: the domestic and foreign supply of natural gas; the price of foreign imports; overall domestic and global economic conditions; the consumption pattern of industrial consumers, electricity generators and residential users; weather conditions; technological advances affecting energy consumption; domestic and foreign governmental regulations; proximity and capacity of gas pipelines and other transportation facilities; and the price and availability of alternative fuels. Many of these factors may be beyond our control. In particular, while demand for natural gas recovered to pre-recession levels, the U.S. natural gas industry continues to face concerns of oversupply due to the success of new shale plays and continued drilling in these plays, despite lower gas prices, to meet drilling commitments. Lower natural gas prices may not only decrease our revenues on a per unit basis, but may also limit our access to capital. A significant decrease in price levels for an extended period would negatively affect us in several ways. These include reduced cash flow, which would decrease funds available for capital expenditures employed to replace reserves or increase production. Also, our access to other sources of capital, such as equity or long-term debt markets, could be severely limited or unavailable. Additionally, lower natural gas prices may reduce the amount of natural gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs, or if our estimates of development costs increase, production data factors change or our exploration results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our natural gas properties. We are required to perform impairment tests on our assets whenever events or changes in circumstances lead to a reduction of the estimated useful life or estimated future cash flows that would indicate that the carrying amount may not be recoverable or whenever management s plans change with respect to those assets. We may incur impairment charges in the future, which could have an adverse effect on our results of operations in the period taken.

If coal customers do not extend existing contracts or do not enter into new long-term coal contracts, profitability of CONSOL Energy s operations could be affected.

During the year ended December 31, 2010, approximately 89% of the coal CONSOL Energy produced was sold under long-term contracts (contracts with terms of one year or more). If a substantial portion of CONSOL Energy s long-term contracts are modified or terminated or if force majeure is exercised, CONSOL Energy would be adversely affected if we are unable to replace the contracts or if new contracts are not at the same level of profitability. If existing customers do not honor current contract commitments, our revenue would be adversely affected. The profitability of our long-term coal supply contracts depends on a variety of factors, which vary from contract to contract and fluctuate during the contract term, including our production costs and other factors. Price changes, if any, provided in long-term supply contracts may not reflect our cost increases, and therefore, increases in our costs may reduce our profit margins. In addition, in periods of declining market prices, provisions in our long-term coal contracts for adjustment or renegotiation of prices and other provisions may increase our exposure to short-term coal price volatility. As a result, CONSOL Energy may not be able to obtain long-term agreements at favorable prices (compared to either market conditions, as they may change from time to time, or our cost structure) and long-term contracts may not contribute to our profitability.

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The loss of, or significant reduction in, purchases by our largest customers could adversely affect our revenues.

For the year ended December 31, 2010, we derived over 25% of our total revenues from sales to our four largest coal and gas customers. At December 31, 2010, we had approximately 21 coal supply agreements with these customers that expire at various times from 2011 to 2030. We are currently discussing the extension of existing agreements or entering into new long-term agreements with some of these customers, but these negotiations may not be successful and these customers may not continue to purchase coal from us under long-term coal supply agreements. If any one of these four customers were to significantly reduce their purchases of coal from us, or if we were unable to sell coal to them on terms as favorable to us as the terms under our current agreements, our financial condition and results of operations could suffer.

Our ability to collect payments from our customers could be impaired if their creditworthiness declines or if they fail to honor their contracts with us.

Our ability to receive payment for coal and gas sold and delivered depends on the continued creditworthiness of our customers. Some power plant owners may have credit ratings that are below investment grade. If the creditworthiness of our customers declines significantly, our $200 million accounts receivable securitization program and our business could be adversely affected. In addition, if customers refuse to accept shipments of our coal for which they have an existing contractual obligation, our revenues will decrease and we may have to reduce production at our mines until our customer s contractual obligations are honored.

The availability and reliability of transportation facilities and fluctuations in transportation costs could affect the demand for our coal or impair our ability to supply coal to our customers. Similarly, our gas business depends on gathering, processing and transportation facilities owned by others and the disruption of, capacity constraints in, or proximity to pipeline systems could limit sales of our gas.

Coal producers depend upon rail, barge, trucking, overland conveyor and other systems to provide access to markets. Disruption of transportation services because of weather-related problems, strikes, lock-outs, break-downs of locks and dams or other events could temporarily impair our ability to supply coal to customers and adversely affect our profitability. Transportation costs represent a significant portion of the delivered cost of coal and, as a result, the cost of delivery is a critical factor in a customer s purchasing decision. Increases in transportation costs could make our coal less competitive.

We gather, process and transport our gas to market by utilizing pipelines and facilities owned by others. If pipelines and facilities do not exist near our producing wells, if pipeline or facility capacity is limited or if pipeline or facility capacity is unexpectedly disrupted, our gas sales could be limited, reducing our profitability. If we cannot access processing pipeline transportation facilities, we may have to reduce our production of gas or vent our produced gas to the atmosphere because we do not have facilities to store excess inventory. If our sales of gas are reduced because of transportation or processing constraints, our revenues will be reduced, and our unit costs will also increase. If pipeline quality tariffs change, we might be required to install additional processing equipment which could increase our costs. The pipeline could also curtail our flows until the gas delivered to their pipeline is in compliance.

Competition within the coal and gas industries may adversely affect our ability to sell our products. Increased competition or a loss of our competitive position could adversely affect our sales of, or our prices for, our coal and gas products, which could impair our profitability.

CONSOL Energy competes with coal producers in various regions of the United States and with some foreign coal producers for domestic sales primarily to electric power generators. CONSOL Energy also competes with both domestic and foreign coal producers for sales in international markets. Demand for our coal by our principal customers is affected by the delivered price of competing coals, other fuel supplies and alternative

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generating sources, including nuclear, natural gas, oil and renewable energy sources, such as hydroelectric and wind power. CONSOL Energy sells coal to foreign electricity generators and to the more specialized metallurgical coal market, both of which are significantly affected by international demand and competition. Increases in coal prices could encourage existing producers to expand capacity or could encourage new producers to enter the market. If overcapacity results, prices could fall or we may not be able to sell our coal, which would reduce revenue.

The gas industry is intensely competitive with companies from various regions of the United States. We compete with these companies and we may compete with foreign companies for domestic sales. Many of the companies we compete with are larger and have greater financial, technological, human and other resources. If we are unable to compete, our company, our operating results and financial position may be adversely affected. In addition, larger companies may be able to pay more to acquire new gas properties for future exploration, limiting our ability to replace gas we produce or to grow our production. Our ability to acquire additional properties and to discover new gas resources also depends on our ability to evaluate and select suitable properties and to consummate these transactions in a highly competitive environment.

We could be negatively affected if we fail to negotiate a new agreement with the United Mine Workers of America, if we enter into a new agreement which significantly increases our labor costs or if we otherwise fail to maintain satisfactory labor relations.

As of December 31, 2010, we had 8,630 employees. Approximately 34% of these employees are represented by the United Mine Workers of America (UMWA) and union operations generated approximately 49% of our U.S. coal production during the year ended December 31, 2010. Our current collective bargaining agreement with the UMWA expires on December 31, 2011. If we do not negotiate a new collective bargaining agreement with the UMWA, we may incur prolonged strikes and other work stoppages at our union mines. We may also have significant reductions in productivity which can materially adversely affect our business, financial condition and results of operations by significantly reducing our production and sale of coal. If we enter into a new agreement with the UMWA which significantly increases our labor costs relative to other coal companies, our ability to compete with other coal companies may be materially adversely affected. Satisfactory relations with our employees and organized labor is important to our success. If we do not maintain satisfactory labor relations, we may incur strikes, other work stoppages, or have reduced productivity.

The characteristics of coal may make it costly for electric power generators and other coal users to comply with various environmental standards regarding the emissions of impurities released when coal is burned which could cause utilities to replace coal-fired power plants with alternative fuels. In addition, various incentives have been proposed to encourage the generation of electricity from renewable energy sources. A reduction in the use of coal for electric power generation could decrease the volume of our coal sales and adversely affect our results of operation.

Coal contains impurities, including sulfur, mercury, chlorine and other elements or compounds, many of which are released into the air when coal is burned. Complying with regulations on the emissions of impurities can be costly for electric power generators. For example, in order to meet the federal Clean Air Act limits for sulfur dioxide emissions from electric power plants, coal users will need to install scrubbers, use sulfur dioxide emission allowances (some of which they may purchase), or switch to other fuels. Each option has limitations. Lower sulfur coal may be more costly to purchase on an energy basis than higher sulfur coal depending on mining and transportation costs. The cost of installing scrubbers is significant and emission allowances may become more expensive as their availability declines. Switching to other fuels may require expensive modification of existing plants. Because higher sulfur coal currently accounts for a significant portion of our sales, the extent to which electric power generators switch to alternative fuel could materially affect us. Proposed reductions in emissions of mercury, sulfur dioxides, nitrogen oxides, or particulate matter may require the installation of additional costly control technology or the implementation of other measures, including trading of emission allowances and switching to alternative fuels. The Environmental Protection Agency (EPA) continues to require reduction of nitrogen oxide emissions in a number of eastern states and the District of Columbia and will require reduction of particulate matter emissions over the next several years for areas that do not meet air quality standards for fine particulates. Additional reductions in permissible emission levels of impurities by coal-fired plants will likely make it more costly to operate coal-fired electric power plants and make coal a less attractive fuel alternative for electric power generation in the future.

Apart from actual and potential regulation of emissions from coal-fired plants, state and federal mandates for increased use of electricity from renewable energy sources could have an impact on the market for our coal. Several states have enacted legislative mandates requiring electricity suppliers to use renewable energy sources to generate a certain percentage of power. There have been numerous proposals to establish a similar uniform, national standard although none of these proposals have been enacted to date. Possible advances in technologies and incentives, such as tax credits, to enhance the economics of renewable energy sources could make these sources more competitive with coal. Any reductions in the amount of coal consumed by domestic electric power generators as a result of current or new standards for the emission of impurities or incentives to switch to alternative fuels or renewable energy sources could reduce the demand for our coal, thereby reducing our revenues and adversely affecting our business and results of operations.

Regulation of greenhouse gas emissions as well as uncertainty concerning such regulation could adversely impact the market for coal and natural gas and the regulation of greenhouse gas emissions may increase our operating costs and reduce the value of our coal and gas assets.

While climate change legislation in the U.S. is unlikely in the next several years, the issue of global climate change continues to attract considerable public and scientific attention with widespread concern about the impacts of human activity, especially the emissions of greenhouse gases (GHGs), such as carbon dioxide and methane. Combustion of fossil fuels, such as the coal and gas we produce, results in the creation of carbon dioxide emissions into the atmosphere by coal and gas end users, such as coal-fired electric power generation plants. Numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government that are intended to limit emissions of GHGs. Several states have already adopted measures requiring reduction of GHGs within state boundaries. Internationally, the Kyoto Protocol, which set binding emission targets for developed countries (including the United States but has not been ratified by the United States) expires in 2012 and negotiations are underway for a new protocol. Regulation of GHGs could occur in the United States pursuant to EPA regulation under the Clean Air Act. On December 23, 2010 the EPA announced that it will propose standards for GHG emissions for power plants in July 2011 and issue final standards in May 2012. Apart from governmental regulation, on February 4, 2008, three of Wall Street s largest investment banks announced that they had adopted climate change guidelines for lenders. The guidelines require the evaluation of carbon risks in the financing of electric power generation plants which may make it more difficult for utilities to obtain financing for coal-fired plants.

If comprehensive regulation focusing on GHGs emission reductions is adopted for the United States by the EPA or in other countries where we sell coal, or if utilities were to have difficulty obtaining financing in connection with coal-fired plants, it may make it more costly to operate fossil fuel fired (especially coal-fired) electric power generation plants and make fossil fuels less attractive for electric utility power plants in the future. Depending on the nature of the regulation or legislation, natural gas-fueled power generation could become more economically attractive than coal-fueled power generation, substantially increasing the demand for natural gas. Apart from actual regulation, uncertainty over the regulation of GHG emissions may inhibit utilities from investing in the building of new coal-fired plants to replace older plants or investing in the upgrading of existing coal-fired plants. Any reduction in the amount of coal or possibly natural gas consumed by domestic electric power generators as a result of actual or potential regulation of greenhouse gas emissions could decrease demand for our fossil fuels, thereby reducing our revenues and materially and adversely affecting our business and results of operations. We or our customers may also have to invest in carbon dioxide capture and storage technologies in order to burn coal or natural gas and comply with future GHG emission standards.

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In addition, coalbed methane must be expelled from our underground coal mines for mining safety reasons. Coalbed methane enhances the GHG effect to a greater degree than carbon dioxide. Our gas operations capture coalbed methane from our underground coal mines, although some coalbed methane is vented into the atmosphere when the coal is mined. If regulation of GHG emissions does not exempt the release of coalbed methane, we may have to further reduce our methane emissions, pay higher taxes, incur costs to purchase credits that permit us to continue operations as they now exist at our underground coal mines or perhaps curtail coal production. The amount of coalbed methane we capture is reported, on a voluntarily basis, to the U.S. Department of Energy. We have recorded the amounts we have captured since the early 1990 s.

Foreign currency fluctuations could adversely affect the competitiveness of our coal abroad.

We compete in international markets against coal produced in other countries. Coal is sold internationally in U.S. dollars. As a result, mining costs in competing producing countries may be reduced in U.S. dollar terms based on currency exchange rates, providing an advantage to foreign coal producers. Currency fluctuations among countries purchasing and selling coal could adversely affect the competitiveness of our coal in international markets.

Our coal mining and gas operations are subject to operating risks, which could increase our operating expenses and decrease our production levels which could adversely affect our results of operations. Our coal and gas operations are also subject to hazards and any losses or liabilities we suffer from hazards which occur in our operations may not be fully covered by our insurance policies.

Our coal mining operations are predominantly underground mines. These mines are subject to a number of operating risks that could disrupt operations, decrease production and increase the cost of mining at particular mines for varying lengths of time thereby adversely affecting our operating results. In addition, if coal production declines, we may not be able to produce sufficient amounts of coal to deliver under our long-term coal contracts. CONSOL Energy s inability to satisfy contractual obligations could result in our customers initiating claims against us. The operating risks that may have a significant impact on our coal operations include:

- variations in thickness of the layer, or seam, of coal;
- amounts of rock and other natural materials intruding into the coal seam and other geological conditions that could affect the stability of the roof and the side walls of the mine;
- equipment failures or repairs;
- fires, explosions or other accidents;
- weather conditions; and
- security breaches or terroristic acts.

Our exploration for and production of natural gas also involves numerous operating risks. The cost of drilling, completing and operating wells for coalbed methane (CBM) or other gas is often uncertain, and a number of factors can delay or prevent drilling operations, decrease production and/or increase the cost of our gas operations at particular sites for varying lengths of time thereby adversely affecting our operating results. The operating risks that may have a significant impact on our gas operations include:

- unexpected drilling conditions;

title problems;

pressure or irregularities in geologic formations;

equipment failures or repairs;

fires, explosions or other accidents;

- adverse weather conditions;
- reductions in natural gas prices;
- security breaches or terroristic acts;
- pipeline ruptures; and
- unavailability or high cost of drilling rigs, other field services and equipment.

Although we maintain insurance for a number of hazards, we may not be insured or fully insured against the losses or liabilities that could arise from a significant accident in our coal or gas operations.

Our focus on new development projects in our operating areas and other unexplored areas increases the risks inherent in our gas and oil activities.

We hold substantial acreage on which there are no proved gas reserves in Pennsylvania, Ohio, Kentucky, West Virginia and Tennessee. Over time, we plan to drill a number of wells in our undeveloped acreage. These exploration, drilling and production activities will be subject to many risks, including the risk that CBM or other natural gas is not present in sufficient quantities in the coal seam or target strata, or that sufficient permeability does not exist for the gas to be produced economically. Drilling for CBM, other natural gas and oil may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient net gas reserves to return a profit after deducting drilling, operating and other costs. We cannot be certain that the wells we drill in these new areas will be productive or that we will recover all or any portion of our investments.

A decrease in the availability or increase in the costs of commodities, key services, or capital equipment used in mining or gas operations, such as steel, liquid fuels and rubber products we use in mining operations or drilling rigs we use to drill gas wells in our gas operations, could impact our cost of production and decrease our anticipated profitability.

Coal mines consume large quantities of key services, capital equipment and commodities including steel, copper, rubber products and liquid fuels. Some commodities, such as steel, are needed to comply with roof control plans required by regulation. The prices we pay for these services and products are strongly impacted by the global market. A rapid or significant increase in the costs of commodities, key services or capital equipment we use in our operations could impact our mining operations costs because we may have a limited ability to negotiate lower prices, and, in some cases, may not have a ready substitute.

In gas operations we contract with third parties for well services, related equipment, and qualified experienced field personnel to drill wells and conduct field operations. The demand for these services in the natural gas and oil industry can fluctuate significantly, often in correlation with natural gas and oil prices causing periodic shortages. These shortages may lead to escalating prices, the possibility of poor services, inefficient drilling operations and personnel injuries. Such pressures will likely increase the actual cost of services, extend the time to secure such services and add costs for damages due to accidents sustained from the over use of equipment and inexperienced personnel. Higher oil and natural gas prices generally stimulate increased demand and result in increased prices for drilling equipment, crews and associated supplies, equipment and services. In addition, the costs and delivery times of equipment and supplies are substantially greater in periods of peak demand. Accordingly, we cannot assure that we will be able to obtain necessary drilling equipment and supplies in a timely manner or on satisfactory terms, and we may experience shortages of, or increases in the costs of, drilling equipment, crews and associated supplies, equipment and services in the future. Any such delays and price increases could adversely affect our ability to pursue our drilling program and our results of operations.

We attempt to mitigate the risks involved with increased industrial activity by entering into take or pay contracts with well service providers which commit them to provide services to us at specified levels and commit us to pay for services at specified levels even if we do not use those services. However, these contracts expose us to economic risk. For example, if the price of natural gas declines and it is not economical to drill and produce additional natural gas, we may have to pay for services that we did not use. This would decrease our cash flow and raise our costs of production.

For mining and drilling operations, CONSOL Energy must obtain, maintain, and renew governmental permits and approvals which if we cannot obtain in a timely fashion would reduce our production, cash flow and results of operations.

Most coal producers in the eastern U.S. are being impacted by government regulations and enforcement to a much greater extent than a few years ago, particularly in light of the renewed focus by environmental agencies and the government generally on the mining industry, including more stringent enforcement of the laws that regulate mining. The pace with which the government issues permits needed for new operations and for on-going operations to continue mining has negatively impacted expected production, especially in Central Appalachia. Environmental groups in Southern West Virginia and Kentucky have challenged state and U.S. Army Corps of Engineers permits for mountaintop mining on various grounds. The most recent challenges have focused on the adequacy of the Corps of Engineers analysis of impacts to streams and the adequacy of mitigation plans to compensate for stream impacts resulting from valley fill permits required for mountaintop mining. In 2007, the U.S. District Court for the Southern District of West Virginia found other operators permits for mining in these areas to be deficient. In February 2009, the U.S. Court of Appeals for the Fourth Circuit reversed that decision, finding that the permits were adequate. However, since that reversal, the U.S. Environmental Protection Agency (EPA) began to more critically review valley fill permits and permits for all types of coal mining operations, and has been recommending that a number of permits be denied because of alleged concerns by the EPA of potential impacts to water quality in streams below mining operations, with cumulative impacts of mining on watersheds. The EPA s objections and an enhanced review process that is being implemented under a federal multi-agency memorandum of understanding have effectively held up the issuance of permits for all types of mining operations that require Clean Water Act Section 402 discharge permits and Section 404 dredge and fill permits, including surface facilities for underground mines, without any indication as to when normal permitting will resume. CONSOL Energy s surface and underground operations have been impacted to a limited extent to date, but future permits will likely be delayed by the EPA s current position, which will likely adversely impact our surface operations. In addition, the length of time needed to bring a new mine into production has increased by several years because of the increased time required to obtain necessary permits. These delays or denials of mining permits could reduce our production, cash flow and results of operations.

Existing and future government laws, regulations and other legal requirements relating to protection of the environment, health and safety matters and others that govern our business have increased our costs of doing business for both coal and gas, and may restrict both our coal and gas operations.

We are subject to laws, regulations and other legal requirements enacted or adopted by federal, state and local, as well as foreign authorities relating to protection of the environment and health and safety matters. These include those legal requirements that govern discharges of substances into the air and water, the management and disposal of hazardous substances and wastes, the cleanup of contaminated sites, groundwater quality and availability, plant and wildlife protection, reclamation and restoration of mining or drilling properties after mining or drilling is completed, the installation of various safety equipment in our mines, control of surface subsidence from underground mining and work practices related to employee health and safety. Complying with these requirements, including the terms of our permits, has had, and will continue to have, a significant effect on our costs of operations and competitive position. For example, we have agreed to commence operation by May 30, 2013 of a new advanced waste water treatment plant to treat the discharge of mine water from our Blacksville #2, Loveridge and Robinson Run mines. This treatment plant will cost an estimated $110 to $120 million to construct. In addition, we could incur substantial costs as a result of violations under environmental and health and safety laws. Any additional laws, regulations and other legal requirements enacted or adopted by federal, state and local, as well as foreign authorities or new interpretations of existing legal requirements by regulatory bodies relating to the protection of the environment and health and safety matters could further affect our costs of operations and competitive position.

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For example, the federal Clean Water Act and corresponding state laws affect coal mining and gas operations by imposing restrictions on discharges into regulated surface waters. Permits requiring regular monitoring and compliance with effluent limitations and reporting requirements govern the discharge of pollutants into regulated waters. The Clean Water Act and corresponding state laws (including those relating to protection of impaired waters (not meeting state water quality standards) through the use of effluent limitations established so that all discharges to the impaired stream do not exceed Total Maximum Daily Load (TMDL) levels of the pollutants causing the impairment; anti-degradation regulations which protect state designated high quality/exceptional use streams by restricting or prohibiting discharges which result in degradation; and requirements to treat discharges from coal mining properties for non-traditional pollutants requiring expensive treatment technologies, such as total dissolved solids, chlorides and selenium; and protecting streams, wetlands, other regulated water sources and associated riparian lands from the surface impacts of underground mining) may cause CONSOL Energy to incur additional costs that could adversely affect our operating results, financial condition and cash flows or may prevent us from being able to mine portions of our reserves. The Clean Water Act is being used by opponents of mountain top removal mining as a means to challenge permits. Also, beginning in early 2009, the EPA has relied upon the Clean Water Act to become more actively involved in the permitting of mountain top removal mining operations and other coal mining operations requiring permits to place fill material in streams. In addition, CONSOL Energy incurs and will continue to incur costs associated with the investigation and remediation of environmental contamination under the federal Comprehensive Environmental Response, Compensation, and Liability Act (Superfund) and similar state statutes and has been named as a potentially responsible party at Superfund sites in the past.

Additionally, the gas industry is subject to extensive legislation and regulation, which is under constant review for amendment or expansion. Any changes may affect, among other things, the pricing or marketing of gas production. State and local authorities regulate various aspects of gas drilling and production activities, including the drilling of wells (through permit and bonding requirements), the spacing of wells, the unitization or pooling of gas properties, environmental matters, safety standards, market sharing and well site restoration. If we fail to comply with statutes and regulations, we may be subject to penalties, which would decrease our profitability.

Our mines are subject to stringent federal and state safety regulations that increase our cost of doing business at active operations and may place restrictions on our methods of operation. In addition, government inspectors under certain circumstances, have the ability to order our operations to be shut down based on safety considerations. A mine could be shut down for an extended period of time if a disaster were to occur at it.

Stringent health and safety standards were imposed by federal legislation when the Federal Coal Mine Health and Safety Act of 1969 was adopted. The Federal Coal Mine Safety and Health Act of 1977 expanded the enforcement of safety and health standards of the Coal Mine Health and Safety Act of 1969 and imposed safety and health standards on all (non-coal as well as coal) mining operations. Regulations are comprehensive and affect numerous aspects of mining operations, including training of mine personnel, mining procedures, the equipment used in mine emergency procedures, mine plans and other matters. The additional requirements of the Mine Improvement and New Emergency Response Act of 2006 (the Miner Act) and implementing federal regulations include, among other things, expanded emergency response plans, providing additional quantities of breathable air for emergencies, installation of refuge chambers in underground coal mines, installation of two-way communications and tracking systems for underground coal mines, new standards for sealing mined out areas of underground coal mines, more available mine rescue teams and enhanced training for emergencies. Most states in which CONSOL Energy operates have programs for mine safety and health regulation and enforcement. We believe that the combination of federal and state safety and health regulations in the coal mining industry is, perhaps, the most comprehensive system for protection of employee safety and health affecting any industry. Most aspects of mine operations, particularly underground mine operations, are subject to extensive regulation. The various requirements mandated by law or regulation can place restrictions on our methods of operations, creating a significant effect on operating costs and productivity. In addition, government inspectors under certain

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circumstances, have the ability to order our operation to be shut down based on safety considerations. If a disaster were to occur at one of our mines, it could be shutdown for an extended period of time and our reputation with our customers could be materially damaged.

In West Virginia there are areas where drainage from coal mining operations contains concentrations of selenium that without treatment would result in violations of state water quality standards that are set to protect fish and other aquatic life. CONSOL Energy has two operations with selenium discharges. CONSOL Energy and other coal companies are working to expeditiously develop cost effective means to remove selenium from mine water. If such technology is not developed promptly, the only available effective treatment technologies are expensive to construct and operate which will increase coal production costs.

Our operations may impact the environment or cause exposure to hazardous substances, and our properties may have environmental contamination, which could result in liabilities to us.

Our operations currently use hazardous materials and generate limited quantities of hazardous wastes from time to time. Drainage flowing from or caused by mining activities can be acidic with elevated levels of dissolved metals, a condition referred to as acid mine drainage. We could become subject to claims for toxic torts, natural resource damages and other damages as well as for the investigation and clean up of soil, surface water, groundwater, and other media. Such claims may arise, for example, out of conditions at sites that we currently own or operate, as well as at sites that we previously owned or operated, or may acquire. Our liability for such claims may be joint and several, so that we may be held responsible for more than our share of the contamination or other damages, or for the entire share.

We maintain extensive coal refuse areas and slurry impoundments at a number of our mining complexes. Such areas and impoundments are subject to extensive regulation. Our coal refuse areas and slurry impoundments are designed, constructed, and inspected by our company and by regulatory authorities according to stringent environmental and safety standards. Structural failure of a slurry impoundment or coal refuse area could result in extensive damage to the environment and natural resources, such as bodies of water that the coal slurry reaches, as well as liability for related personal injuries and property damages, and injuries to wildlife. Some of our impoundments overlie mined out areas, which can pose a heightened risk of failure and of damages arising out of failure. If one of our impoundments were to fail, we could be subject to claims for the resulting environmental contamination and associated liability, as well as for fines and penalties.

These and other similar unforeseen impacts that our operations may have on the environment, as well as exposures to hazardous substances or wastes associated with our operations, could result in costs and liabilities that could adversely affect us.

CONSOL Energy has reclamation, mine closing and gas well plugging obligations. If the assumptions underlying our accruals are inaccurate, we could be required to expend greater amounts than anticipated.

The Surface Mining Control and Reclamation Act establishes operational, reclamation and closure standards for all aspects of surface mining as well as most aspects of deep mining. Also, state laws require us to plug gas wells and reclaim well sites after the useful life of our gas wells has ended. CONSOL Energy accrues for the costs of current mine disturbance, gas well plugging and of final mine closure, including the cost of treating mine water discharge where necessary. Estimates of our total reclamation, mine-closing liabilities and gas well plugging, which are based upon permit requirements and our experience, were approximately $671 million at December 31, 2010. The amounts recorded are dependent upon a number of variables, including the estimated future closure costs, estimated proven reserves, assumptions involving profit margins, inflation rates, and the assumed credit-adjusted risk-free interest rates. Furthermore, these obligations are unfunded. If these accruals are insufficient or our liability in a particular year is greater than currently anticipated, our future operating results could be adversely affected.

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CONSOL Energy faces uncertainties in estimating our economically recoverable coal and gas reserves, and inaccuracies in our estimates could result in lower than expected revenues, higher than expected costs and decreased profitability.

There are uncertainties inherent in estimating quantities and values of economically recoverable coal reserves, including many factors beyond our control. As a result, estimates of economically recoverable coal reserves are by their nature uncertain. Information about our reserves consists of estimates based on engineering, economic and geological data assembled and analyzed by our staff. Some of the factors and assumptions which impact economically recoverable coal reserve estimates include:

- geological conditions;
- historical production from the area compared with production from other producing areas;
- the assumed effects of regulations and taxes by governmental agencies;
- assumptions governing future prices; and
- future operating costs, including the cost of materials.

Similarly, natural gas reserves require subjective estimates of underground accumulations of natural gas and assumptions concerning natural gas prices, production levels, and operating and development costs. As a result, estimated quantities of proved gas reserves and projections of future production rates and the timing of development expenditures may be incorrect. Over time, material changes to reserve estimates may be made, taking into account the results of actual drilling, testing and production. Also, we make certain assumptions regarding natural gas prices, production levels, and operating and development costs that may prove incorrect. Any significant variance from these assumptions to actual figures could greatly affect our estimates of our gas reserves, the economically recoverable quantities of natural gas attributable to any particular group of properties, the classifications of gas reserves based on risk of recovery, and estimates of the future net cash flows. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of gas we ultimately recover being different from reserve estimates. The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated natural gas reserves. We base the estimated discounted future net cash flows from our proved gas reserves on historical average prices and costs. However, actual future net cash flows from our gas and oil properties also will be affected by factors such as:

- geological conditions;
- changes in governmental regulations and taxation;
- the amount and timing of actual production;
- future operating costs; and
- capital costs of drilling new wells.

The timing of both our production and our incurrence of expenses in connection with the development and production of natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general. In addition, if natural gas prices decline by $0.10 per thousand cubic feet, then the pre-tax present value using a 10% discount rate of our proved gas reserves as of December 31, 2010 would decrease from $2.8 billion to $2.7 billion. The standardized Generally Accepted Accounting Principle measure associated with this decline of $0.10 per thousand cubic feet, would be approximately $1.6 billion.

Each of the factors which impacts reserve estimation may in fact vary considerably from the assumptions used in estimating the reserves. For these reasons, estimates of coal and gas reserves may vary substantially. Actual production, revenues and expenditures with respect to our coal and gas reserves will likely vary from estimates, and these variances may be material. As a result, our estimates may not accurately reflect our actual coal and gas reserves.

We may incur additional costs and delays to produce coal and gas because we have to acquire additional property rights to perfect our title to coal or gas rights.

While chain of title for our coal estate generally has been established, there may be defects in it that we do not realize until we have committed to developing those properties or coal reserves. As such, the title to the coal estate that we intend to mine may contain defects. In order to conduct our mining operations on properties where these defects exist, we may incur unanticipated costs perfecting title.

Some of the gas rights we believe we control are in areas where we have not yet done any exploratory or production drilling. Many of these properties were acquired primarily for the coal rights, and, in many cases were acquired years ago. While chain of title work for the coal estate was generally established, in some cases, the gas estate title work is less developed. Our practice is to perform a thorough title examination of the gas estate before we commence drilling activities and to acquire any additional rights needed to perfect our ownership of the gas estate for development and production purposes. We may incur substantial costs to acquire these additional property rights and the acquisition of the necessary rights may not be feasible in some cases. Our inability to obtain these rights may adversely impact our ability to develop those properties. Some states permit us to produce the gas without perfected ownership under an administrative process known as pooling, which require us to give notice to all potential claimants and pay royalties into escrow until the undetermined rights are resolved. As a result, we may have to pay royalties to produce gas on acreage that we control and these costs may be material. Further, the pooling process is time-consuming and may delay our drilling program in the affected areas.

Our subsidiaries, primarily Fairmont Supply Company, is a co-defendant in various asbestos litigation cases which could result in making payments in the future that are material.

One of our subsidiaries, Fairmont Supply Company (Fairmont), which distributes industrial supplies, currently is named as a defendant in approximately 22,500 asbestos claims in state courts in Pennsylvania, Ohio, West Virginia, Maryland, Mississippi, New Jersey, Texas and Illinois. Because a very small percentage of products manufactured by third parties and supplied by Fairmont in the past may have contained asbestos and many of the pending claims are part of mass complaints filed by hundreds of plaintiffs against a hundred or more defendants, it has been difficult for Fairmont to determine how many of the cases actually involve valid claims or plaintiffs who were actually exposed to asbestos-containing products supplied by Fairmont. In addition, while Fairmont may be entitled to indemnity or contribution in certain jurisdictions from manufacturers of identified products, the availability of such indemnity or contribution is unclear at this time and, in recent years, some of the manufacturers named as defendants in these actions have sought protection from these claims under bankruptcy laws. Fairmont has no insurance coverage with respect to these asbestos cases. For the year ended December 31, 2010, payments by Fairmont with respect to asbestos cases have not been material. Other of our subsidiaries may also have asbestos claims against them. Our current estimates related to these asbestos claims, individually and in the aggregate, are immaterial to the financial position, results of operations and cash flows of CONSOL Energy. However, it is reasonably possible that payments in the future with respect to pending or future asbestos cases may be material to the financial position, results of operations or cash flows of CONSOL Energy.

CONSOL Energy and its subsidiaries are subject to various legal proceedings, which may have an adverse effect on our business.

We are party to a number of legal proceedings in the normal course of business activities. Defending these actions, especially purported class actions, can be costly, and can distract management. For example, we are a defendant in four pending purported class action lawsuits dealing with such diverse matters as the propriety of our acquisition of the noncontrolling interest of CNX Gas, our right to natural gas production in some areas, and asserting that we are responsible for Hurricane Katrina and the damage it caused. There is the potential that the costs of defending litigation in an individual matter or the aggregation of many matters could have an adverse effect on our cash flows, results of operations or financial position. See Note 24 Commitments and Contingent Liabilities in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion of pending legal proceedings.

CONSOL Energy has obligations for long-term employee benefits for which we accrue based upon assumptions which, if inaccurate, could result in CONSOL Energy being required to expense greater amounts than anticipated.

CONSOL Energy provides various long-term employee benefits to inactive and retired employees. We accrue amounts for these obligations. At December 31, 2010, the current and non-current portions of these obligations included:

- postretirement medical and life insurance ($3.3 billion);
- coal workers black lung benefits ($184.5 million);
- salaried retirement benefits ($163.4 million); and
- workers compensation ($174.5 million).

However, if our assumptions are inaccurate, we could be required to expend greater amounts than anticipated. Salary retirement benefits are funded in accordance with ERISA regulations. The other obligations are un-funded. In addition, the federal government and several states in which we operate consider changes in workers compensation and black lung laws from time to time. Such changes, if enacted, could increase our benefit expense.

Due to our participation in a multi-employer pension plan, we have exposure under that plan that extends beyond what our obligation would be with respect to our employees.

Certain of our subsidiaries are obligated to contribute to a multi-employer defined benefit pension plan for United Mine Workers of America (UMWA) retirees. In the event of a partial or complete withdrawal by us from such pension plan, we would be liable for a proportionate share of such pension plan s unfunded vested benefits, as determined by the plan s actuary. Based on the information available from the plan s administrators, we believe that our portion of the contingent liability represented by the pension plan s unfunded vested benefits, in the case of our withdrawal from the pension plan or in the case of the termination of the pension plan, could be material to our financial position and results of operations. In the event that any other contributing employer withdraws from such pension plan and such employer (or any member in its controlled group) cannot satisfy their obligations under the plan at the time of withdrawal, then we, along with the other remaining contributing employers, would be liable for an increase in our proportionate share of the pension plan s unfunded vested benefits at the time of the withdrawal from the pension plan or its termination.

The minimum funding level requirements of the Pension Protection Act of 2006 (Pension Act) applicable to single employer and multi-employer defined benefit pension plans, coupled with significant investment asset losses suffered by such pension plans during the recent decline in equity markets and the current volatile economic environment, have exposed CONSOL Energy to having to make additional cash contributions to fund the pension benefit plans which we sponsor and the multi-employer pension benefit plan in which we participate.

Certain subsidiaries of CONSOL Energy participate in a defined benefit multi-employer pension plan (1974 Pension Trust) negotiated with the United Mine Workers of America (UMWA) and contained in the National

Bituminous Coal Wage Agreement (NBCWA). The 1974 Pension Trust is overseen by a board of trustees, consisting of two union-appointed trustees and two employer-appointed trustees. The trustees responsibilities include selection of the plan s investment policy, asset allocation, individual investment of plan assets and the administration of the plan. The benefits provided by the 1974 Pension Trust to the participating employees are determined based on age and years of service at retirement. The current 2007 NBCWA will expire on December 31, 2011 and calls for contribution amounts to be paid into the multi-employer 1974 Pension Trust based principally on hours worked by UMWA-represented employees. The contribution rates called for by the current NBCWA are: $3.50 per hour worked in 2008; $4.25 per hour worked in 2009, $5.00 per hour worked in 2010 and $5.50 per hour worked in 2011. For the plan year ended June 30, 2010, approximately 18% of retirees and surviving spouses receiving benefits from the 1974 Pension Trust last worked at signatory subsidiaries of CONSOL Energy.

As of June 30, 2010, the most recent date for which information is available, the 1974 Pension Trust was underfunded. This determination was made in accordance with Employer Retirement Income Security Act of 1974 (ERISA) calculations, with a total actuarial asset value of $5.1 billion and a total actuarial accrued liability of $6.8 billion, or a funded percentage of approximately 76%. On October 7, 2010, certain subsidiaries of CONSOL Energy received notice from the trustees of the 1974 Pension Trust stating that the plan is considered to be seriously endangered for the plan year beginning July 1, 2010. Under the Pension Protection Act (Pension Act), a funded percentage of 80% should be maintained for this multi-employer pension plan, and if the plan is determined to have a funded percentage of less than 80% it will be deemed to be endangered or seriously endangered , and if less than 65%, it will be deemed to be in critical status. The funded percentage certified by the actuary for the 1974 Pension Trust was determined to be approximately 76% under the Pension Act.

Certain subsidiaries of CONSOL Energy face risks and uncertainties by participating in the 1974 Pension Trust. All assets contributed to the plan are pooled and available to provide benefits for all participants and beneficiaries. As a result, contributions made by signatory subsidiaries of CONSOL Energy benefit employees of other employers. If the 1974 Pension Trust fails to meet ERISA s minimum funding requirements or fails to develop and adopt a required rehabilitation plan, a nondeductible excise tax of five percent of the accumulated funding deficiency may be imposed on an employer s contribution to this multi-employer pension plan. As a result of the 1974 Pension Trust s seriously endangered status, steps must be taken under the Pension Act to improve the funded status of the plan. These steps could result in requiring certain signatory subsidiaries of CONSOL Energy to make additional contributions pursuant to a funding improvement plan adopted and implemented in accordance with the Pension Act and, therefore, could have a material impact on our operating results. See Note 17 Other Employee Benefit Plans in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion.

If lump sum payments made to retiring salaried employees pursuant to CONSOL Energy s defined benefit pension plan exceed the total of the service cost and the interest cost in a plan year, CONSOL Energy would need to make an adjustment to operating results equaling the unrecognized actuarial gain or loss resulting from each individual who received a lump sum payment in that year, which may result in an adjustment that could reduce operating results.

CONSOL Energy s defined benefit pension plans for salaried employees allows such employees to receive a lump-sum distribution for benefits earned up through December 31, 2005 in lieu of annual payments when they retire from CONSOL Energy. Employers Accounting for Settlements and Curtailments of Defined Benefit Pension Plans for Terminations Benefits requires that if the lump-sum distributions made for a plan year exceed the total of the service cost and interest cost for the plan year, CONSOL Energy would need to recognize for that year s results of operations an adjustment equaling the unrecognized actuarial gain or loss resulting from each individual who received a lump sum in that year. This type of adjustment may result in a reduction in operating results.

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Acquisitions that we have completed, acquisitions that we may undertake in the future, as well as expanding existing company mines, involve a number of risks, any of which could cause us not to realize the anticipated benefits and to the extent we engage in divestitures, the timing and proceeds thereof may not provide anticipated benefits.

On April 30, 2010 we completed the Dominion Acquisition for approximately $3.5 billion. We could encounter difficulties with the Dominion Acquisition, such as the need to revisit assumptions about gas reserves, future gas production, revenues, capital expenditures and operating costs, including realizing anticipated synergies, the loss of key employees or commercial relationships or the need to address unanticipated liabilities. If we cannot successfully integrate our business, we may fail to realize the expected benefits of the acquisition. We also continually seek to grow our business by adding and developing coal and gas reserves through acquisitions and by expanding the production at existing mines and existing gas operations. If we are unable to successfully integrate the companies, businesses or properties we acquire, our profitability may decline and we could experience an adverse effect on our business, financial condition, or results of operations. Mine expansion, gas operation expansion and acquisition transactions involve various inherent risks, including:

- uncertainties in assessing the value, strengths, and potential profitability of, and identifying the extent of all weaknesses, risks, contingent and other liabilities (including environmental liabilities) of expansion and acquisition opportunities;
- the potential loss of key customers, management and employees of an acquired business;
- the ability to achieve identified operating and financial synergies anticipated to result from an expansion or an acquisition opportunity;
- problems that could arise from the integration of the acquired business;
- unanticipated changes in business, industry or general economic conditions that affect the assumptions underlying our rationale for pursuing the expansion of the acquisition opportunity; and
- we may have to assume cleanup or reclamation obligations or other unanticipated liabilities in connection with these acquisitions.

From time to time part of our business and financing plans include the divestiture of certain assets. However, we do not control the timing or the terms associated with them. Divestitures may not provide anticipated benefits or anticipated proceeds and may not occur when forecasted.

CONSOL Energy s rights plan may have anti-takeover effects that may discourage a change of control even if doing so might be beneficial to our stockholders.

On December 19, 2003, CONSOL Energy adopted a rights plan which, in certain circumstances, including a person or group acquiring, or the commencement of a tender or exchange offer that would result in a person or group acquiring, beneficial ownership of more than 15% of the outstanding shares of CONSOL Energy common stock, would entitle each right holder to receive, upon exercise of the right, shares of CONSOL Energy common stock having a value equal to twice the right exercise price. For example, at an exercise price of $80 per right, each right not otherwise voided would entitle its holders to purchase $160 worth of shares of CONSOL Energy common stock for $80. Assuming that shares of CONSOL Energy common stock had a per share value of $16 at such time, the holder of each right would be entitled to purchase ten shares of CONSOL Energy common stock for $80, or a price of $8 per share, one half of its then market price. This and other provisions of CONSOL Energy s rights plan could make it more difficult for a third party to acquire CONSOL Energy, which could hinder stockholders ability to receive a premium for CONSOL Energy stock over the prevailing market prices.

Our financial performance could be adversely affected by our debt.

As of December 31, 2010, our total indebtedness was approximately $3.695 billion of which approximately $155 million was under our senior secured credit facility, $129 million was under CNX Gas secured revolving

credit facility, $200 million was under the securitization facility, $250 million was under our 7.875% senior secured notes due March 2012, $1.5 billion was under our 8.00% senior unsecured notes due April 2017, $1.25 billion was under our 8.25% senior unsecured notes due April 2020, $103 million was under our Baltimore Port Facility 5.75% revenue bonds due September 2025, $66 million of capitalized leases due through 2021, and $42 million of miscellaneous debt. The degree to which we are leveraged could have important consequences, including, but not limited to:

- increasing our vulnerability to general adverse economic and industry conditions;
- limiting our ability to obtain additional financing to fund future working capital, capital expenditures, acquisitions, development of our coal and gas reserves or other general corporate requirements;
- limiting our flexibility in planning for, or reacting to, changes in our business and in the coal and gas industries; and
- placing us at a competitive disadvantage compared to less leveraged competitors.

Our senior secured credit facility and the indentures governing our 7.875% senior secured notes, and our 8.00% and 8.25% senior unsecured notes limit the incurrence of additional indebtedness unless specified tests or exceptions are met. In addition, our senior secured credit agreement and the indentures governing our 8.00% and 8.25% senior unsecured notes subject us to financial and/or other restrictive covenants. Under our senior secured credit agreement, we must comply with certain financial covenants on a quarterly basis including a minimum interest coverage ratio, a maximum leverage ratio, and a maximum senior secured leverage ratio, as defined. Our senior secured credit agreement and the indentures governing our 8.00% and 8.25% senior unsecured notes impose a number of restrictions upon us, such as restrictions on granting liens on our assets, making investments in joint ventures, paying dividends, selling assets and engaging in acquisitions. Failure by us to comply with these covenants could result in an event of default that, if not cured or waived, could have an adverse effect on us.

If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to sell assets, seek additional capital or seek to restructure or refinance our indebtedness. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations. In the absence of such operating results and resources, we could face substantial liquidity problems and might be required to sell material assets or operations to attempt to meet our debt service and other obligations. Our senior secured credit agreement and the indentures governing our 8.00% and 8.25% senior unsecured notes restrict our ability to sell assets and use the proceeds from the sales. We may not be able to consummate those sales or to obtain the proceeds which we could realize from them and these proceeds may not be adequate to meet any debt service obligations then due.

Unless we replace our gas reserves, our gas reserves and production will decline, which would adversely affect our business, financial condition, results of operations and cash flows.

Producing natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Because total estimated proved reserves include our proved undeveloped reserves at December 31, 2010, production is expected to decline even if those proved undeveloped reserves are developed and the wells produce as expected. The rate of decline will change if production from our existing wells declines in a different manner than we have estimated and can change under other circumstances. Thus, our future natural gas reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs.

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Our shale gas drilling and production operations requires both adequate sources of water to use in the fracturing process as well as the ability to dispose of water after hydraulic fracturing. Our CBM gas drilling and production operations also require the removal and disposal of water from the coal seams from which we produce gas. If we cannot find adequate sources of water for our use or are unable to dispose of the water we use or remove it from the strata at a reasonable cost and within applicable environmental rules, our ability to produce gas economically and in commercial quantities could be impaired.

As part of our drilling and production in the Marcellus shale, we use hydraulic fracturing processes. Thus, we need access to adequate sources of water to use in our Marcellus shale operations. Further, we must remove the water that we use to fracture our shale gas wells when it flows back to the well-bore. In addition, in our CBM drilling and production, coal seams frequently contain water that must be removed and disposed of in order for the gas to detach from the coal and flow to the well bore. Our inability to locate sufficient amounts of water with respect to our Marcellus Shale operations, or the inability to dispose of or recycle water used in our Marcellus shale and our CBM operations, could adversely impact our operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste. These include, but are not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of natural gas. These impositions may increase operating costs and cause delays, interruptions or termination of operations, the extent of which cannot be predicted, all of which could have an adverse affect on our operations and financial performance. For example, concerns over the impact of hydraulic fracturing on watersheds have led to a moratorium on drilling in the Marcellus shale in New York State.

Our hedging activities may prevent us from benefiting from price increases and may expose us to other risks.

To manage our exposure to fluctuations in the price of natural gas, we enter into hedging arrangements with respect to a portion of our expected production. As of January 24, 2011, we had hedges on approximately 69.2 billion cubic feet of our 2011 natural gas production, 26.4 billion cubic feet of our 2012 natural gas production, 7.5 billion cubic feet of our 2013 natural gas production and 7.5 billion cubic feet of our 2014 natural gas production. To the extent that we engage in hedging activities, we may be prevented from realizing the benefits of price increases above the levels of the hedges.

In addition, such transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- the counterparties to our contracts fail to perform the contracts; or
- the creditworthiness of our counterparties or their guarantors is substantially impaired.

If our gas hedges would no longer qualify for hedge accounting, we will be required to mark them to market and recognize the adjustments through current year earnings. This may result in more volatility in our income in future periods.

Item 1B. ***Unresolved Staff Comments.***

None.

Item 2. ***Properties.***

See Coal Operations and Gas Operations in Item 1 of this 10-K for a description of CONSOL Energy s properties.

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Item 3. ***Legal Proceedings.***

The first through the seventeenth paragraphs of Note 24 Commitments and Contingent Liabilities in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K are incorporated herein by reference.

Item 4. ***Submission of Matters to a Vote of Security Holders.***

None.

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PART II

Item 5. ***Market for Registrant s Common Equity and Related Stockholder Matters and Issuer Purchases of Equity Securities.***

Our common stock is listed on the New York Stock Exchange under the symbol CNX. The following table sets forth for the periods indicated the range of high and low sales prices per share of our common stock as reported on the New York Stock Exchange and the cash dividends declared on the common stock for the periods indicated:

	High	Low	Dividends
Year Period Ended December 31, 2010:			
Quarter Ended March 31, 2010	$ 56.34	$ 42.28	$ 0.10
Quarter Ended June 30, 2010	$ 46.26	$ 33.73	$ 0.10
Quarter Ended September 30, 2010	$ 39.22	$ 31.21	$ 0.10
Quarter Ended December 31, 2010	$ 48.81	$ 36.67	$ 0.10
Year Period Ended December 31, 2009:			
Quarter Ended March 31, 2009	$ 36.59	$ 22.58	$ 0.10
Quarter Ended June 30, 2009	$ 43.57	$ 24.57	$ 0.10
Quarter Ended September 30, 2009	$ 49.28	$ 29.75	$ 0.10
Quarter Ended December 31, 2009	$ 52.87	$ 42.81	$ 0.10

As of December 31, 2010, there were 176 holders of record of our common stock.

The following performance graph compares the yearly percentage change in the cumulative total shareholder return on the common stock of CONSOL Energy to the cumulative shareholder return for the same period of a peer group and the Standard & Poor s 500 Stock Index. The peer group is comprised of CONSOL Energy, Alliance Resource Partners, Alpha Natural Resources Inc., Anadarko Petroleum Corp., Apache Corp., Arch Coal Inc., Cabot Oil & Gas Corp., Callon Petroleum Co., Chesapeake Energy Corp., Cimarex Energy Co., Comstock Resources Inc., Denbury Resources Inc., Devon Energy Corp., Encana Corp., EOG Resources Inc., International Coal Group Inc., James River Coal Co., Massey Energy Co., Newfield Exploration Co., Nexen Inc., Noble Energy Inc., Peabody Energy Corp., Penn Virginia Corp., Pioneer Natural Resources Co., Rio Tinto PLC (ADR), St Mary Land & Exploration, Stone Energy Corp., Ultra Petroleum Corp., and Westmoreland Coal Co. The graph assumes that the value of the investment in CONSOL Energy common stock and each index was $100 at December 31, 2005. The graph also assumes that all dividends were reinvested and that the investments were held through December 31, 2010.

	2005	2006	2007	2008	2009	2010
CONSOL Energy Inc.	100.0	99.4	222.3	90.0	158.1	156.0
Peer Group	100.0	100.7	146.7	104.7	152.7	168.1
S&P 500 Stock Index	100.0	115.6	121.8	77.2	97.3	111.7

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Cumulative Total Shareholder Return Among CONSOL Energy Inc., Peer Group and

S&P 500 Stock Index

The above information is being furnished pursuant to Regulation S-K, Item 201 (e) (Performance Graph).

On January 28, 2011, CONSOL Energy s board of directors declared a regular quarterly dividend of $0.10 per share, payable on February 18, 2011, to shareholders of record on February 8, 2011.

The declaration and payment of dividends by CONSOL Energy is subject to the discretion of CONSOL Energy s Board of Directors, and no assurance can be given that CONSOL Energy will pay dividends in the future. CONSOL Energy s Board of Directors determines whether dividends will be paid quarterly. The determination to pay dividends will depend upon, among other things, general business conditions, CONSOL Energy s financial results, contractual and legal restrictions regarding the payment of dividends by CONSOL Energy, planned investments by CONSOL Energy and such other factors as the Board of Directors deems relevant. Our credit facility limits our ability to pay dividends in excess of an annual rate of $0.40 per share when our leverage ratio exceeds 4.50 to 1.00 or our availability is less than or equal to $100 million. The leverage ratio was 3.48 to 1.00 and our availability was approximately $1.1 billion at December 31, 2010. The credit facility does not permit dividend payments in the event of default. The indentures to the 2017 and 2020 notes limits dividends to $0.40 per share annually unless several conditions are met. Conditions include no defaults, ability to incur additional debt and other payment limitations under the indentures. There were no defaults under our credit facility or the indentures in the year ended December 31, 2010.

See Part III, Item 12. Security ownership of Certain Beneficial Owners and Management and Related Stockholders Matters for information relating to CONSOL Energy s equity compensation plans.

Item 6. ***Selected Financial Data.***

The following table presents our selected consolidated financial and operating data for, and as of the end of, each of the periods indicated. The selected consolidated financial data for, and as of the end of, each of the years ended December 31, 2010, 2009, 2008, 2007 and 2006 are derived from our audited Consolidated Financial Statements. Certain reclassifications of prior year data have been made to conform to the year ended December 31, 2010 presentation. The selected consolidated financial and operating data are not necessarily indicative of the results that may be expected for any future period. The selected consolidated financial and operating data should be read in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and the financial statements and related notes included in this report.

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STATEMENT OF INCOME DATA

(In thousands except per share data)

	For the Years Ended December 31, 2010	2009	2008	2007	2006
Sales Outside(A)	$ 4,938,703	$ 4,311,791	$ 4,181,569	$ 3,324,346	$ 3,286,522
Sales Purchased Gas(A)	11,227	7,040	8,464	7,628	43,973
Sales Gas Royalty Interests(A)	62,869	40,951	79,302	46,586	51,054
Freight Outside(A)	125,715	148,907	216,968	186,909	162,761
Other Income	97,507	113,186	166,142	196,728	170,861
Total Revenue and Other Income	5,236,021	4,621,875	4,652,445	3,762,197	3,715,171
Cost of Goods Sold and Other Operating Charges (exclusive of depreciation, depletion and amortization shown below)	3,262,327	2,757,052	2,843,203	2,352,000	2,249,776
Acquisition and Financing Fees	65,363				
Purchased Gas Costs	9,736	6,442	8,175	7,162	44,843
Gas Royalty Interests Costs	53,775	32,376	73,962	39,921	41,879
Freight Expense	125,544	148,907	216,968	186,909	162,761
Selling, General and Administrative Expenses	150,210	130,704	124,543	108,664	91,150
Depreciation, Depletion and Amortization	567,663	437,417	389,621	324,715	296,237
Interest Expense	205,032	31,419	36,183	30,851	25,066
Taxes Other Than Income	328,458	289,941	289,990	258,926	252,539
Black Lung Excise Tax Refund		(728)	(55,795)	24,092	
Total Costs	4,768,108	3,833,530	3,926,850	3,333,240	3,164,251
Earnings Before Income Taxes	467,913	788,345	725,595	428,957	550,920
Income Taxes	109,287	221,203	239,934	136,137	112,430
Net Income	358,626	567,142	485,661	292,820	438,490
Less: Net Income Attributable to Noncontrolling Interest	(11,845)	(27,425)	(43,191)	(25,038)	(29,608)
Net Income Attributable to CONSOL Energy Inc. Shareholders	$ 346,781	$ 539,717	$ 442,470	$ 267,782	$ 408,882
Earnings Per Share:					
Basic(B)	$ 1.61	$ 2.99	$ 2.43	$ 1.47	$ 2.23
Dilutive(B)	$ 1.60	$ 2.95	$ 2.40	$ 1.45	$ 2.20
Weighted Average Number of Common Shares Outstanding:					
Basic	214,920,561	180,693,243	182,386,011	182,050,627	183,354,732
Dilutive	217,037,804	182,821,136	184,679,592	184,149,751	185,638,106
Dividends Paid Per Share	$ 0.40	$ 0.40	$ 0.40	$ 0.31	$ 0.28

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BALANCE SHEET DATA

(In thousands)

	December 31,				
	2010	2009	2008	2007	2006
Working (deficiency) capital	$ (549,779)	$ (487,550)	$ (527,926)	$ (333,242)	$ 174,372
Total assets	12,070,610	7,775,401	7,535,458	6,333,490	5,663,332
Short-term debt	484,000	522,850	722,700	372,900	
Long-term debt (including current portion)	3,210,921	468,302	490,752	507,208	552,263
Total deferred credits and other liabilities	4,283,674	3,849,428	3,716,021	3,325,231	3,228,653
CONSOL Energy Inc. Stockholders equity	2,944,477	1,785,548	1,462,187	1,214,419	1,066,151

OTHER OPERATING DATA

(unaudited)

	Years Ended December 31,				
	2010	2009	2008	2007	2006
Coal:					
Tons sold (in thousands)(C)(D)	63,906	58,123	66,236	65,462	68,920
Tons produced (in thousands)(D)	62,352	59,389	65,077	64,617	67,432
Productivity (tons per manday)(D)	34.39	38.21	36.80	41.29	38.41
Average production cost ($ per ton produced)(D)	$ 46.55	$ 44.87	$ 41.08	$ 33.68	$ 32.53
Average sales price of tons produced ($ per ton produced)(D)	$ 61.35	$ 58.28	$ 48.77	$ 40.60	$ 38.99
Recoverable coal reserves (tons in millions)(D)(E)	4,401	4,520	4,543	4,526	4,272
Number of active mining complexes (at end of period)	12	11	17	15	14
Gas:					
Net sales volumes produced (in billion cubic feet)(D)	127.9	94.4	76.6	58.3	56.1
Average sales price ($ per mcf)(D)(F)	$ 5.83	$ 6.68	$ 8.99	$ 7.20	$ 7.04
Average cost ($ per mcf)(D)	$ 3.90	$ 3.44	$ 3.67	$ 3.33	$ 2.88
Proved reserves (in billion cubic feet)(D)(G)	3,732	1,911	1,422	1,343	1,265

CASH FLOW STATEMENT DATA

(In thousands)

	For the Years Ended December 31,				
	2010	2009	2008	2007	2006
Net cash provided by operating activities	$ 1,131,312	$ 1,060,451	$ 989,864	$ 558,633	$ 664,547
Net cash used in investing activities(H)	(5,543,974)	(845,341)	(1,098,856)	(972,104)	(661,546)
Net cash provided by (used in) financing activities	4,379,849	(288,015)	205,853	231,239	(119,758)

OTHER FINANCIAL DATA

(Unaudited)

(In thousands)

	Years Ended December 31,				
	2010	2009	2008	2007	2006
Capital expenditures	$ 1,154,024	$ 920,080	$ 1,061,669	$ 743,114	$ 690,546
EBIT(I)	653,458	786,520	685,574	421,978	531,009
EBITDA(I)	1,221,121	1,223,937	1,075,195	746,693	827,246
Ratio of earnings to fixed charges(J)	2.74	11.76	10.67	7.48	11.36

(A) See Note 25 Segment Information in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for sales and freight by operating segment.

(B) Basic earnings per share are computed using weighted average shares outstanding. Differences in the weighted average number of shares outstanding for purposes of computing dilutive earnings per share are due to the inclusion of the weighted average dilutive effect of employee and non-employee share-based compensation granted, totaling 2,117,243 shares, 2,127,893 shares, 2,293,581 shares, 2,099,124 shares, and 2,283,374 shares for the year ended December 31, 2010, 2009, 2008, 2007, and 2006, respectively.

(C) Includes sales of coal produced by CONSOL Energy and purchased from third parties. Of the tons sold, CONSOL Energy purchased the following amount from third parties: 0.3 million tons in the year ended December 31, 2010, 0.3 million tons in the year ended December 31, 2009, 1.7 million tons in the year ended December 31, 2008, 0.5 million tons in the year ended December 31, 2007, 1.3 million tons in the year ended December 31, 2006.

(D) Amounts include intersegment transactions. For entities that are not wholly owned but in which CONSOL Energy owns an equity interest, includes a percentage of their net production, sales and reserves equal to CONSOL Energy s percentage equity ownership. For coal, the proportionate share of recoverable reserves for equity affiliates was 172, 170, 171 and 179 tons at December 31, 2010, 2009, 2008 and 2007 respectively. Sales of coal produced by equity affiliates were 0.6 million tons in the year ended December 31, 2010, 0.4 million tons in the year ended December 31, 2009, 0.2 million tons in the year ended December 31, 2008 and 0.1 million tons in the year ended December 31, 2007. Recoverable reserves and production amounts related to 2006 for coal equity affiliates were immaterial. For gas, amounts include 100% of CNX Gas basis; they exclude the noncontrolling interest reduction. There was no equity in affiliates at December 31, 2010, 2009 and 2008. The proportionate share of proved gas reserves for equity affiliates was 3.6 Bcfe at December 31, 2007 and 2.2 Bcfe at December 31, 2006. Sales of gas produced by equity affiliates were 0.32 Bcfe for the year ended December 31, 2007 and 0.22 Bcfe for the year ended December 2006.

(E) Represents proven and probable coal reserves at period end.

(F) Represents average net sales price including the effect of derivative transactions.

(G) Represents proved developed and undeveloped gas reserves at period end.

(H) Net cash used in investing activities includes $3,470,212 and $991,034 in the year ended December 31, 2010 related to the Dominion Acquisition and the purchase of CNX Gas Non-Controlling Interest, respectively. The year ended December 31, 2007 includes $296,724 related to the acquisition of AMVEST.

(I) EBIT is defined as earnings before deducting net interest expense (interest expense less interest income) and income taxes. EBITDA is defined as earnings before deducting net interest expense (interest expense less interest income), income taxes and depreciation, depletion and amortization. Although EBIT and EBITDA are not measures of performance calculated in accordance with generally accepted accounting principles, management believes that they are useful to an investor in evaluating CONSOL Energy because they are widely used in the coal industry as measures to evaluate a company s operating performance before debt expense and cash flow. Financial covenants in our credit facility include ratios based on EBITDA. EBIT and

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EBITDA do not purport to represent cash generated by operating activities and should not be considered in isolation or as a substitute for measures of performance in accordance with generally accepted accounting principles. In addition, because EBIT and EBITDA are not calculated identically by all companies, the presentation here may not be comparable to other similarly titled measures of other companies. Management s discretionary use of funds depicted by EBIT and EBITDA may be limited by working capital, debt service and capital expenditure requirements, and by restrictions related to legal requirements, commitments and uncertainties. A reconcilement of EBIT and EBITDA to financial net income is as follows:

	Years Ended December 31,				
	2010	2009	2008	2007	2006
Net Income	$ 346,781	$ 539,717	$ 442,470	$ 267,782	$ 408,882
Add: Interest expense	205,032	31,419	36,183	30,851	25,066
Less: Interest income	(7,642)	(5,052)	(2,363)	(12,792)	(15,369)
Less: Interest income included in black lung excise tax refund		(767)	(30,650)		
Add: Income tax expense	109,287	221,203	239,934	136,137	112,430
Earnings before interest and taxes (EBIT)	653,458	786,520	685,574	421,978	531,009
Add: Depreciation, depletion and amortization	567,663	437,417	389,621	324,715	296,237
Earnings before interest, taxes and depreciation, depletion and amortization (EBITDA)	$ 1,221,121	$ 1,223,937	$ 1,075,195	$ 746,693	$ 827,246

(J) For purposes of computing the ratio of earnings to fixed charges, earnings represent income before income taxes plus fixed charges. Fixed charges include (a) interest on indebtedness (whether expensed or capitalized), (b) amortization of debt discounts and premiums and capitalized expenses related to indebtedness and (c) the portion of rent expense we believe to be representative of interest.

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Item 7. ***Management s Discussion and Analysis of Financial Condition and Results of Operations.***

General

The global recovery for steel producers continued to gain strength in 2010. Global blast furnace iron production was 15% higher in 2010 than 2009. It is expected that global steel production rates will grow another 5-6% in 2011. The recent flooding in Australia has heightened steel producers concerns over security of supply of metallurgical coals. We believe that steel producers who have a large exposure to limited geographic supply sources will diversify their supply base to reduce the risk of supply disruptions. We believe this will increase the demand for U.S. metallurgical coals.

Demand for U.S. metallurgical coal is expected to be very strong in 2011 due to global growth as well as improving domestic demand. U.S. steel mill utilization is currently at 72%, and there are increasingly optimistic signs for the domestic metallurgical coal markets. Prices for hot rolled coil steel (HRC) have been steadily increasing, buoyed by strong U.S. auto sales figures in December 2010. U.S. auto markets are expected to continue recovery in 2011, which will improve the outlook for the North American steel markets. Given the continued projected growth in the global markets as well as an accelerating North American recovery, we anticipate that metallurgical coal markets will gain strength through 2011.

The steam coal outlook continues to improve, driven by declining inventories and increasing demand due to general economic recovery and favorable weather. Coal inventories at utilities were steadily drawn down in 2010. We believe that inventories at the end of December were 22-25 million tons below inventories at the same time last year. We believe that bituminous coal comprises half of this reduction in inventories and inventories in our major market areas (Mid Atlantic and South Atlantic markets) are lower than in other regions of the U.S.

Demand for Northern Appalachian coal is not only influenced by domestic demand from utilities but also from European utilities and cross-over demand from metallurgical markets. We expect European demand for U.S. coal to be very strong in 2011 as European coal prices have recently hit two-year highs. South African and Colombian coals continue to be pulled to developing countries like, China, Brazil and India, allowing North America coal to fill the void. We expect 2011 demand for Northern Appalachian coal will be very strong from four sources: traditional markets, as a metallurgical crossover product, as a replacement for declining Central Appalachian production and from European utilities.

A strong start to the 2010 winter season has helped improve natural gas demand; however, the natural gas industry continues to face concerns of oversupply. The supply of natural gas remains very strong due to the success of new shale plays and drilling in these plays to meet drilling commitments. Natural gas storage for 2010 is similar to 2009 levels and industrial demand for gas continues to grow as the economy recovers. In addition to small increases in demand, we are seeing more supply responses to the current price environment. Canadian gas imports have decreased and liquefied natural gas (LNG) imports have failed to materialize. We are also seeing more companies redirect capital away from lower return gas basins towards liquids rich targets. We expect these trends to help curb the growth in gas supply over the next one to two years.

Several significant transactions occurred in the year ended December 31, 2010, including the following;

On April 30, 2010, CONSOL Energy completed the acquisition of the Appalachian oil and gas exploration and production business of Dominion Resources, Inc., (Dominion Acquisition) for a cash payment of approximately $3.5 billion, which was principally allocated to oil and gas properties, wells and well related equipment. The acquisition included approximately 1 trillion cubic feet equivalents (Tcfe) of net proved reserves and 1.46 million acres of oil and gas rights within the Appalachian Basin. Included in the acquired acreage are approximately 500 thousand prospective net Marcellus Shale acres located predominantly in southwestern Pennsylvania and northern West Virginia. The acquisition enhances CONSOL Energy s position in the strategic Marcellus Shale fairway by increasing its development assets.

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On March 31, 2010, CONSOL Energy completed an offering of 44.3 million shares of common stock, which generated net proceeds of approximately $1.8 billion. On April 1, 2010, CONSOL Energy issued $1.5 billion of 8.00% senior unsecured notes due in 2017 and $1.25 billion of 8.25% senior unsecured notes due in 2020. The equity and senior note proceeds were used in part to complete the Dominion Acquisition. CONSOL Energy also amended and expanded its previous $1.0 billion revolving credit facility to $1.5 billion. CNX Gas also amended and expanded its previous $200 million revolving credit facility to $700 million. These revolving credit facilities were amended and expanded to provide liquidity for future cash needs of the company.

On June 1, 2010, CONSOL Energy completed the acquisition of the outstanding shares of CNX Gas common stock that it did not previously own for a cash payment of approximately $967 million. The transaction was effected by means of a cash tender offer for CNX Gas shares at a price of $38.25 per share, followed by a short-form merger at the same price, in which CNX Gas became a wholly owned subsidiary of CONSOL Energy. CONSOL Energy previously owned approximately 83.3% of the approximately 151 million shares of CNX Gas common stock outstanding. An additional $24 million cash payment was made to cancel previously vested CNX Gas stock options. CONSOL Energy financed the acquisition of CNX Gas shares by means of internally generated funds, borrowings under its credit facilities and proceeds from its March 31, 2010 offering of common stock.

CONSOL Energy sold approximately 2.4 million tons of high volatile metallurgical coal overseas in 2010, to meet the growing global demand for steel and steel products. This coal was previously sold by CONSOL Energy on the domestic steam market at lower average sales prices. The new market for this coal has allowed expanded margins for coals we produce primarily from the Pittsburgh #8 seam.

CONSOL Energy sold approximately 4.6 million tons of low volatile metallurgical coal produced at our Buchanan Mine, of which approximately 72% was sold into the overseas metallurgical market at higher average prices than CONSOL Energy has received in the recent past.

CONSOL Energy s gas operations, together with the producing wells purchased in the Dominion Acquisition, produced a record 127.9 billion cubic feet of gas. Although gas prices remain depressed, increased production has contributed to CONSOL Energy s net income.

Because of the rapidly changing regulatory environment in which CONSOL Energy operates and various other issues that impact our industries, costs of our coal and gas production in the future may be impacted. The impacts of these changes cannot be determined with certainty at this time. Situations that may impact our costs include the following items:

As a result of mine disasters as well as a continuing effort to improve the safety of coal mining, state and federal mine regulators have recently adopted and proposed new mine safety requirements, which impact our operations. These regulations include, for example: new standards for the incombustible content of combined coal dust, rock dust and other dust in underground coal mines; new standards for the amount of respirable dust in underground coal mines; the requirement to equip underground mining equipment with proximity detection devices capable of shutting the equipment down if a person gets too close to the equipment; and the requirements to replace existing seals underground with stronger seals and to monitor and regulate the quality of the mine atmosphere in sealed areas to prevent explosions or reduce their impact. Further, it is likely that regulatory authorities will increase the number of inspections at coal mines and will more strictly enforce existing safety laws and regulations. New safety requirements and enhanced enforcement efforts typically increase the costs of our coal mining operations, which would impact our margins and results of operations.

State and Federal environmental regulators have recently adopted and proposed new environmental regulations, and adopted new interpretations of existing regulations, which impact our operations. These include: mandatory reporting of greenhouse gas emissions from underground coal mines and gas operations; potential regulation of greenhouse gas emissions from coal fired electric generating facilities, a significant market for our coal; adoption of more stringent emission limits for currently

regulated pollutants from coal fired electric generating facilities; regulation of coal combustion residuals under the Resource Conservation and Recovery Act; potential regulation of hydraulic fracturing of gas wells; more stringent interpretations of Clean Water Act requirements resulting in the need to remove constituents of mine drainage that cannot be removed with existing treatment facilities, and/or limiting areas that can be mined; more involvement by the EPA in review of applications for new mines and renewals of applications for existing mines resulting in significant permit delays; and reconsideration of regulations relating to conducting surface mining operations near streams. Such new and enhanced environmental protection requirements are likely to increase the costs of our coal mining operations, which would impact our margins and results of operations.

Enactment of laws or passage of regulations by the federal government, individual states or other countries regarding emissions from combustion of fossil fuels or establishing renewable energy standards could result in decreased consumption of coal and gas and lead to the switching to other energy technologies for electricity. While climate change legislation in the U.S. is unlikely in the next several years, it is likely that some form of legislation addressing global climate change or establishing renewable energy standards, or both, will be enacted in the future. At this time it is not possible to determine when such legislation will be enacted or the impact of potential legislation on our operations or financial condition. Whether or not climate change legislation is enacted, the U.S. Environmental Protection Agency (EPA) has found that carbon dioxide may reasonably be anticipated to endanger public health or welfare (an endangerment finding) under the Clean Air Act and is proposing regulations that would restrict carbon dioxide emissions from certain sources; however, the EPA s endangerment finding and its authority to adopt such regulations is being challenged in the courts. Although, efforts to enact greenhouse gas legislation have failed, the EPA is proceeding with greenhouse gas regulations. In September 2009, the EPA finalized the Mandatory Reporting of Greenhouse Gas Rule. The current version of this rule requires reporting of emissions from coal mines and gas wells and associated facilities. In December 2010, the EPA announced a proposed schedule for establishing greenhouse gas emission limits for fossil fuel fired electric generating facilities (proposed regulations by July 2011 and final regulations by May 2012.) The level of impact will depend on numerous factors including the specific requirements imposed by legislation or rules, the timing of legislation or rules, time period for compliance, and the timing and commercial development of technologies associated with carbon capture and sequestration. Ultimately, the impact of possible legislation or rules on our business will depend on the degree to which electric power generators are forced to reduce their consumption of coal or gas, install expensive technologies for carbon capture and sequestration, or switch to alternative energy sources. CONSOL Energy believes that if climate change legislation or rules are passed, gas will be impacted to a lesser degree than coal and the company has made strategic investment decisions to change its portfolio of assets to increase the contribution of gas to the company s business. In fact, over the short term, CONSOL Energy expects gas to be the preferred fuel source for new power plants. Over the long term, CONSOL Energy believes that with the development of new technologies for carbon capture and sequestration, both coal and gas will continue to be used as clean and competitive fuel sources for electricity generation.

As standards continue to become more stringent on water discharge quality, CONSOL Energy will incur additional costs to build and operate facilities to treat water. For example, CONSOL Energy completed construction of a new mine water treatment facility at its Buchanan Mine in Virginia in 2010 for a total cost of approximately $86 million. It is also in the process of designing and permitting another facility to process mine water from the active Blacksville #2, Loveridge and Robinson Run Mines and the closed Four States Mine in northern West Virginia. The existing facility and the one being permitted are designed to remove chlorides to insure compliance with state and Federal water discharge standards. These new facilities will also remove other dissolved constituents, such as sulfates. Construction of the West Virginia facility is scheduled to be completed in 2013 with a total estimated cost of approximately $110 million to $120 million. These facilities utilize state of the art equipment for water treatment including reverse osmosis, evaporation and crystallization technologies. In 2011, CONSOL Energy will also complete construction of pipelines with diffusers to convey high-chloride mine water from the active

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Shoemaker Mine and the closed Windsor Mine and discharge those waters into approved mixing zones in the Ohio River. Finally, at the Bailey Mine in Pennsylvania, CONSOL Energy will start construction in 2011 of a new water handling system that will prevent discharge of water containing high total dissolved solids into area streams.

Although these items primarily impact CONSOL Energy s coal business, management continues to believe our coal business will be successful in developing economic solutions to address these matters. Our coal business is also expected to continue to generate expanding margins due to:

- Our low-volatile metallurgical coal business with our Buchanan Mine;
- Our high-volatile metallurgical coal business, where we are selling Northern Appalachian coal to Asian and Brazilian steelmakers at expanded margins; and
- Lower thermal coal stockpiles.

We believe that coal will continue to provide the base load of the nation s energy needs. Through our efforts during the last 10 years to improve our operating efficiencies at our major coal production sites, we believe we are well positioned to continue to provide our customers with low cost, high-British thermal units (btus) coal that we expect will generate returns to our shareholders.

Finally, CONSOL Energy is managing several other significant matters that will affect our business in the future:

- The United Mine Workers of America (UMWA) collective bargaining agreement expires on December 31, 2011. Results of future agreements could have a significant effect on future cash flows and earnings of CONSOL Energy. If a new collective bargaining agreement is not reached, CONSOL Energy could be impacted by work stoppages, which would impact our future coal production.
- Consolidation of CONSOL Energy s customer base continues to occur. These consolidations may impact the creditworthiness of our customers, the amount of coal or gas a customer buys in a given year, and the terms of new sales contracts.
- Health care reform legislation included a revision to coal workers pneumoconiosis (CWP) regulations which will enable claimants to more easily qualify for a benefit. The legislation also allows for a five-year look back on claims to determine if a previously denied claim will now become eligible. The new legislation impacted CONSOL Energy s CWP liability by approximately $46 million, as described more fully in Note 16 Coal Workers Pneumoconiosis (CWP) and Workers Compensation in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K.
- CONSOL Energy continues to evaluate the potential sale of certain Central Appalachia metallurgical coal properties as well as other non-core assets. To date, there are no definitive agreements in place and evaluation of proposals continue.

Results of Operations

Year Ended December 31, 2010 Compared with Year Ended December 31, 2009

Net Income Attributable to CONSOL Energy Shareholders

CONSOL Energy reported net income attributable to CONSOL Energy shareholders of $347 million, or $1.60 per diluted share, for the year ended December 31, 2010. Net income attributable to CONSOL Energy shareholders was $540 million, or $2.95 per diluted share, for the year ended December 31, 2009. See below for a detailed explanation by segment of the variance incurred in the period-to-period comparison.

The total coal segment includes steam coal, high volatile metallurgical coal, low volatile metallurgical coal and other coal. The total coal segment contributed $536 million of earnings before income tax for the year ended December 31, 2010 compared to $546 million for the year ended December 31, 2009. The total coal segment sold 63.0 million tons of coal produced from CONSOL Energy mines, excluding our portion of tons sold from equity affiliates, in the year ended December 31, 2010 compared to 57.4 million tons in the year ended December 31, 2009. The average sales price and total costs per ton for all active coal operations were as follows:

	Year Ended December 31,			
	2010	2009	Variance	Percent Change
Average Sales Price per ton sold	$ 61.33	$ 58.70	$ 2.63	4.5%
Average Costs per ton sold	45.44	43.13	2.31	5.4%
Margin	$ 15.89	$ 15.57	$ 0.32	2.1%

The higher average sales price per ton sold reflects an additional 2.3 million tons of low volatile metallurgical coal and 2.4 million tons of high volatile metallurgical coal sold in 2010 compared to 2009. The low volatile metallurgical coal segment also had a higher average sales price in 2010 compared to 2009 reflecting the strengthening of the global steel market and steel related products. The high volatile metallurgical coal global market has allowed approximately 2.4 million tons of coal to be sold as a metallurgical product at an average sales price of $72.89 per ton. This coal historically would have been sold on the steam market where our average price for 2010 was $53.76 per ton.

Average costs per ton of coal sold have increased in the period-to-period comparison due primarily to additional labor, higher supply and maintenance costs, and increased other costs which are directly related to the higher sales prices received for tons sold. Additional labor costs per ton are related to the net addition of approximately 330 employees. The additional labor was attributed to the Shoemaker Mine resuming production in 2010 after being idled throughout 2009 to complete the replacement of the track haulage system to a more efficient belt haulage system. Additional labor was also added in order to run our mines more safely, to prepare for the expected retirement of a significant portion of our work force over the next five years, and to keep the development of the longwall panels ahead of longwall advancement. Additional supply costs were attributable to compliance with new safety regulations such as fire retardant belts, additional equipment maintenance and various changes in roof control measures. Costs directly related to the price received for coal sales have also increased. These costs include royalty expenses and various production taxes.

The total gas segment includes coalbed methane (CBM), conventional, Marcellus and other gas. The total gas segment contributed $180 million of earnings before income tax for the year ended December 31, 2010 compared to $263 million for the year ended December 31, 2009. Total gas production was 127.9 billion cubic feet for the year ended December 31, 2010 compared to 94.4 billion cubic feet for the year ended December 31, 2009.

The average sales price and total costs for all active gas operations were as follows:

	Year Ended December 31,			
	2010	2009	Variance	Percent Change
Average Sales Price per thousand cubic feet sold	$ 5.83	$ 6.68	$ (0.85)	(12.7)%
Average Costs per thousand cubic feet sold	3.90	3.44	0.46	13.4%
Margin	$ 1.93	$ 3.24	$ (1.31)	(40.4)%

Total gas segment outside sales revenues were $746 million for the year ended December 31, 2010 compared to $630 million for the year ended December 31, 2009. The increase was primarily due to the 35.5%

increase in volumes sold, offset, in part, by the 12.7% reduction in average price per thousand cubic feet sold. The decrease in average sales price is the result of various gas swap transactions that occurred throughout both periods. These gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 52.1 billion cubic feet of our produced gas sales volumes for the year ended December 31, 2010 at an average price of $7.66 per thousand cubic feet. These financial hedges represented approximately 51.6 billion cubic feet of our produced gas sales volumes for the year ended December 31, 2009 at an average price of $8.76 per thousand cubic feet. Average gas sales prices excluding the impact of hedging were up slightly in the period-to-period comparison.

Total gas unit costs increased for the year ended December 31, 2010 compared to the year ended December 31, 2009 primarily due to the impact of the higher cost structure of the producing wells purchased in the Dominion Acquisition. These wells increased total operating costs by $0.78 per thousand cubic feet due to the higher maintenance costs, higher gathering and transportation costs and lower volumes produced compared to the legacy CONSOL Energy wells. Excluding the impact of these purchased wells, unit costs improved $0.32 per thousand cubic feet primarily due to the additional volumes produced. Volumes increased in the period-to-period comparison due to the on-going drilling program and the additional volumes from the wells purchased in the Dominion Acquisition.

The other segment includes industrial supplies activity, terminal and river service activity, income taxes and other business activities not assigned to the coal or gas segment.

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TOTAL COAL SEGMENT ANALYSIS for the year ended December 31, 2010 compared to the year ended December 31, 2009:

The coal segment contributed $536 million of earnings before income tax in the year ended December 31, 2010 compared to $546 million in the year ended December 31, 2009. Variances by the individual coal segments are discussed below.

	For the Year Ended December 31, 2010					Difference to Year Ended December 31, 2009				
	Steam Coal	High Vol Met Coal	Low Vol Met Coal	Other Coal	Total Coal	Steam Coal	High Vol Met Coal	Low Vol Met Coal	Other Coal	Total Coal
Sales:										
Produced Coal	$ 3,001	$ 172	$ 680	$ 12	$ 3,865	$ (121)	$ 172	$ 431	$ 12	$ 494
Purchased Coal				34	34				(5)	(5)
Total Outside Sales	3,001	172	680	46	3,899	(121)	172	431	7	489
Freight Revenue				126	126				(23)	(23)
Other Income	8	7		48	63	1	7		(22)	(14)
Total Revenue and Other Income	3,009	179	680	220	4,088	(120)	179	431	(38)	452
Costs and Expenses:										
Total operating costs	1,850	69	232	294	2,445	110	69	116	(10)	285
Total provisions	198	7	27	129	361	18	7	11	101	137
Total administrative & other costs	142	5	18	97	262	(2)	5	8	(2)	9
Depreciation, depletion and amortization	274	11	21	52	358	16	11	8	19	54
Total Costs and Expenses	2,464	92	298	572	3,426	142	92	143	108	485
Freight Expense				126	126				(23)	(23)
Total Cost	2,464	92	298	698	3,552	142	92	143	85	462
Earnings (Loss) Before Income Taxes	$ 545	$ 87	$ 382	$ (478)	$ 536	$ (262)	$ 87	$ 288	$ (123)	$ (10)

STEAM COAL SEGMENT:

The steam coal segment contributed $545 million to total company earnings before income tax in the year ended December 31, 2010 compared to $807 million in the year ended December 31, 2009. The Steam coal revenue and cost components on a per unit basis are as follows:

	2010	2009	Variance	Percent Change
Produced Steam Tons Sold (in millions)	55.8	55.1	0.7	1.3%
Average Sales Price Per Steam Ton Sold	$ 53.76	$ 56.64	$ (2.88)	(5.1)%
Average Operating Costs Per Steam Ton Sold	$ 33.14	$ 31.57	$ 1.57	5.0%
Average Provision Costs Per Steam Ton Sold	$ 3.55	$ 3.27	$ 0.28	8.6%
Average Selling, Administrative and Other Costs Per Steam Ton Sold	$ 2.55	$ 2.60	$ (0.05)	(1.9)%
Average Depreciation, Depletion and Amortization Costs Per Steam Ton Sold	$ 4.90	$ 4.68	$ 0.22	4.7%
Total Costs Per Steam Ton Sold	$ 44.14	$ 42.12	$ 2.02	4.8%
Margin	$ 9.62	$ 14.52	$ (4.90)	(33.7)%

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Steam coal revenue was $3,001 million for the year ended December 31, 2010 compared to $3,122 million for the year ended December 31, 2009. The $121 million decrease was attributable to an average sales price reduction of $2.88 per ton partially offset by a 0.7 million increase in tons sold. Steam coal average sales price is lower in the 2010 period compared to the 2009 period as a result of higher average sales price mines, such as Bailey and Enlow Fork, selling coal in the high volatile metallurgical coal market instead of the steam coal market. This impacted the steam coal segment as a result of leaving more tons sold from lower sales price mines. This has negatively impacted the average sales price on the steam coal segment, although total company revenue has improved. Produced steam inventory was 1.9 million tons at December 31, 2010 compared to 2.9 million tons at December 31, 2009. Steam sales tons were higher in the period-to-period comparison primarily due to the Shoemaker Mine restarting production in early 2010 after being idled throughout 2009 to complete the replacement of the track haulage system. Steam sales tons were also higher as the result of the Blacksville #2 Mine being idled for several months in 2009 in order to manage inventory levels in response to the economic crisis experienced. Blacksville #2 Mine has operated throughout 2010. These increases were offset, in part, due to selling 2.4 million tons on the high volatile metallurgical coal market at approximately $19.13 per ton higher average sales price.

Other income attributable to the steam coal segment represents earnings from our equity affiliate that operates a steam coal mine. The equity in earnings of affiliates is insignificant to the total segment activity.

Operating costs are made up of labor, supplies, maintenance, subsidence, taxes other than income, royalties and preparation plant charges related to the extraction and sale of coal. These costs are reviewed regularly by management and are considered to be the direct responsibility of mine management. Operating costs related to the steam coal segment were $1,850 million for the year ended December 31, 2010 compared to $1,740 million for the year ended December 31, 2009. Higher operating costs in the period-to-period comparison are due to the $1.57 per ton increase in average unit costs of tons sold and 0.7 million of additional tons sold.

Higher average operating costs per unit for steam coal tons sold are primarily related to the following items:

- Steam coal unit costs were higher in 2010 as a result of lower cost mines, such as Bailey and Enlow Fork, selling coal in the high volatile metallurgical coal market. This impacted the steam coal segment due to increased tons sold from higher cost mines.

- Labor costs increased due to the effects of wage increases at the union mines from the current labor contracts. The contracts call for specified hourly wage increases in each year of the contract. Labor costs also increased due to the effects of wage increases at the non-represented mines. Average employee counts also increased approximately 5% at our active mining operations. The additional employees were primarily due to the Shoemaker Mine resuming production in 2010 after being idled during 2009 to complete the replacement of the track haulage system to a more efficient belt haulage system. Additional employees were also added in order to run our mines more safely, to prepare for the expected retirement of a significant portion of our work force over the next five years, and to keep the development of the longwall panels ahead of longwall advancement.

- Health and retirement costs related to the active hourly work force increased due to higher contributions to the multiemployer 1974 pension trust that are required under the National Bituminous Coal Wage Agreement. The contribution rate increased from $4.25 per hour worked by members of the United Mine Workers Union of America (UMWA) in the year ended December 31, 2009 to $5.00 per hour worked in the year ended December 31, 2010. Contributions to the multiemployer plan are expensed as incurred. Health and Retirement costs have also increased in the period-to-period comparison due to higher medical costs for the active hourly work force.

- Power costs increased due to higher rates charged by utility companies and increased usage in the period-to-period comparison.

- Operating costs also increased as a result of the 1.0 million ton decrease in inventory levels.

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The increases in average unit costs of steam coal sold were offset, in part, by the following:

Reduced contract mining fees due to fewer contractors being retained to mine our reserves in the year ended December 31, 2010 compared to the 2009 period.

Average operating costs per steam ton sold decreased due to higher tons sold. Fixed costs are allocated over higher tons resulting in decreased unit costs.

Total CONSOL Energy expenses related to our actuarial liabilities were $287 million for the year ended December 31, 2010 compared to $243 million for the year ended December 31, 2009. The increase of $44 million was due primarily to changes in the discount rates used at the measurement date, which is December 31, and changes in assumptions which affect the amount of actuarial gains and losses amortized into earnings. See Note 15 Pension and Other Postretirement Benefits Plans and Note 16 Coal Workers Pneumoconiosis (CWP) and Workers Compensation in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional detail regarding total company expense.

Total provisions are made up of the expenses related to the Company s long-term liabilities, such as other post employment benefits (OPEB), the salary retirement plan, workers compensation, long-term disability and accretion expense on mine closing and related liabilities. With the exception of accretion expense on mine closing and related liabilities, these expenses are actuarially calculated for the company as a whole. The expenses are then allocated to operational units based on active employee counts or active salary dollars. Accretion is calculated on a mine-by-mine basis. Provisions attributable to the steam coal segment were $198 million for the year ended December 31, 2010 compared to $180 million for the year ended December 31, 2009. Provision costs per steam coal ton sold increased $0.28 per ton in the period-to-period comparison due primarily to higher actuarial expenses, such as OPEB, as discussed above. The overall increase in company costs has increased the total dollars allocated to the steam coal segment. This increase was offset, in part, by additional tons sold by the steam coal segment.

Total Company Selling, General and Administrative Expenses were made up of the following items:

	2010	2009	Variance	Percent Change
Employee wages and related expenses	$ 72	$ 63	$ 9	14.3%
Commissions	12	7	5	71.4%
Miscellaneous	66	61	5	8.2%
Total Company Selling, General and Administrative Expenses	$ 150	$ 131	$ 19	14.5%

Employee wages and related expenses have increased due to additional employees in the selling, general and administrative area primarily related to support staff retained in the Dominion Acquisition and additional hiring to support operations. Increased employee wages and related expenses are also related to additional actuarial expenses discussed above.

Commission expenses increased $5 million due to additional tons for which a third party was owed a commission compared to the prior year period.

Miscellaneous expenses have increased approximately $5 million. The increase was related to an additional $2 million for advertising and promotion fees, an additional $2 million for demurrage charges and an additional $1 million for various other items, none of which were individually material.

Total administrative and other costs related to the steam coal segment were $142 million for the year ended December 31, 2010 and $144 million for the year ended December 31, 2009. Selling, general and administrative costs, excluding selling expense, are allocated to all segments based on a combination of estimated time worked by various support groups and operating costs incurred by the individual segments. Commission expense, which is a component of selling, is charged directly to the mine incurring the cost. Direct

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administrative costs are associated directly with the coal segment of the business and are allocated to various mines based on a combination of estimated time worked and production. Although the total company selling, general and administrative costs have increased, as discussed above, the amount allocated to the steam coal segment has decreased approximately $2 million. The decrease in the amount allocated to the steam coal segment is primarily related to the high volatile metallurgical coal segment. In 2009, these tons and the associated allocation were all included in the steam coal segment.

Depreciation, depletion and amortization costs for the steam coal segment were $274 million for the year ended December 31, 2010 and $258 million for the year ended December 31, 2009. The increase of $16 million, or $0.22 per ton, was due to additional equipment and infrastructure placed into service after 2009, offset, in part, by additional volumes sold.

HIGH VOL METALLURGICAL COAL SEGMENT:

The high volatile metallurgical coal segment contributed $87 million to total company earnings before income tax for the year ended December 31, 2010. There was no activity in this segment in the prior year. This is a new market that has developed in 2010 and is primarily related to selling our Pittsburgh #8 coal into overseas metallurgical coal markets. This coal had historically supplied the domestic steam coal market. The high volatile metallurgical coal revenue and cost components on a per unit basis are as follows:

	2010	2009	Variance	Percent Change
Produced High Vol Met Tons Sold (in millions)	2.4		2.4	100.0%
Average Sales Price Per High Vol Met Ton Sold	$ 72.89	$	$ 72.89	100.0%
Average Operating Costs Per High Vol Met Ton Sold	$ 29.16	$	$ 29.16	100.0%
Average Provision Costs Per High Vol Met Ton Sold	$ 3.08	$	$ 3.08	100.0%
Average Selling, Administrative and Other Costs Per High Vol Met Ton Sold	$ 2.26	$	$ 2.26	100.0%
Average Depreciation, Depletion and Amortization Costs Per High Vol Met Ton Sold	$ 4.61	$	$ 4.61	100.0%
Total Costs per High Vol Met Ton Sold	$ 39.11	$	$ 39.11	100.0%
Margin	$ 33.78	$	$ 33.78	100.0%

The high volatile metallurgical coal segment revenue was $172 million, or an average sales price per ton of $72.89, for the year ended December 31, 2010. Strength in the metallurgical coal market has allowed for the export of Northern Appalachian coal, historically sold domestically on the steam coal market, to crossover to the metallurgical coal markets in Brazil and Asia. Total costs per ton sold of this coal were $39.11 generating a margin of $33.78 per ton sold. This margin exceeds the $9.62 per ton average margin received on steam coal sold in 2010 which is where this coal would have been historically sold.

Other income attributable to the high volatile metallurgical coal segment represents earnings from our equity affiliates that operate mines that sell coal on the high volatile metallurgical coal market. The equity in earnings of affiliates is insignificant to the total segment activity.

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LOW VOL METALLURGICAL COAL SEGMENT:

The low volatile metallurgical coal segment contributed $382 million to total company earnings before income tax for the year ended December 31, 2010 compared to $94 million for the year ended December 31, 2009. The increase was due primarily to the Buchanan Mine being idled for approximately five months of 2009. The mine was idled in 2009 in response to the economic crisis which significantly lowered the demand for low volatile metallurgical coal, primarily due to the decrease in steel demand. The Buchanan Mine has operated throughout all of 2010. The low volatile metallurgical coal revenue and cost components on a per unit basis are as follows:

	2010	2009	Variance	Percent Change
Produced Low Vol Met Tons Sold (in millions)	4.6	2.3	2.3	100.0%
Average Sales Price Per Low Vol Met Ton Sold	$ 146.32	$ 107.72	$ 38.60	35.8%
Average Operating Costs Per Low Vol Met Ton Sold	$ 49.82	$ 50.31	$ (0.49)	(1.0)%
Average Provision Costs Per Low Vol Met Ton Sold	$ 5.90	$ 6.76	$ (0.86)	(12.7)%
Average Selling, Administrative and Other Costs Per Low Vol Met Ton Sold	$ 3.95	$ 4.57	$ (0.62)	(13.6)%
Average Depreciation, Depletion and Amortization Costs Per Low Vol Met Ton Sold	$ 4.57	$ 5.46	$ (0.89)	(16.3)%
Total Costs Per Low Vol Met Ton Sold	$ 64.24	$ 67.10	$ (2.86)	(4.3)%
Margin	$ 82.08	$ 40.62	$ 41.46	102.1%

Average sales price for low volatile metallurgical coal has increased $38.60 per ton, from the prior year, to $146.32 for the year ended December 31, 2010. The increase of 35.8% is mainly due to the strengthening of the global market for steel and steel related products when compared to 2009.

Total costs per ton sold of low volatile metallurgical coal were $64.24 per ton for the year ended December 31, 2010 compared to $67.10 per ton for the year ended December 31, 2009. The $2.86 per ton improvement was related to operating the Buchanan Mine for all of 2010 versus seven months of 2009. The additional tonnage sold in 2010 has reduced the average per unit costs.

OTHER COAL SEGMENT:

The Other Coal segment had a loss before income tax of $478 million for the year ended December 31, 2010 compared to a loss before income tax of $355 million for the year ended December 31, 2009. The Other Coal segment includes purchased coal activities, idled mine activities as well as various other activities assigned to the coal segment but not allocated to each individual mine.

Other Coal segment produced coal sales revenue was $12 million for the year ended December 31, 2010. This revenue includes the sale of incidental tonnage recovered during the reclamation process at idled facilities. The primary focus of activity at these locations is reclaiming disturbed land in accordance with permit requirements after final mining has occurred. The tons sold from these activities are incidental to total company production and sales.

Purchased coal sales were $34 million for the year ended December 31, 2010 compared to $39 million for the year ended December 31, 2009. Purchased coal sales consist of revenues from processing third-party coal in our preparation plants for blending purposes to meet customer coal specifications, coal purchased from third parties and sold directly to our customers and revenues from processing third-party coal in our preparation plants for a fee.

Freight revenue is the amount billed to customers for transportation costs incurred. This revenue is based on weight of coal shipped, negotiated freight rates and method of transportation (i.e. rail, barge, truck, etc.) used by

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the customers to which CONSOL Energy contractually provides transportation services. Freight revenue is offset in freight expense. Freight revenue was $126 million in the year ended December 31, 2010 compared to $149 million for the year ended December 31, 2009. The decrease of $23 million was primarily due to lower tons being shipped on CONSOL Energy freight contracts in the period-to-period comparison.

Miscellaneous other income was $48 million for the year ended December 31, 2010 compared to $70 million for the year ended December 31, 2009. The $22 million decrease was due to the following items:

In the year ended December 31, 2009, $12 million of income was recognized related to contracts with certain customers that were unable to take delivery of previously contracted coal tonnage. These customers agreed to buy out their contracts in order to be released from the requirements of taking delivery of previously committed tons. No such transactions were entered into in the year ended December 31, 2010.

Gain on sales of assets attributable to the Other Coal segment were $9 million for the year ended December 31, 2010 compared to $16 million for the year ended December 31, 2009. The change was related to various transactions that occurred throughout both periods, none of which were individually material.

Coal royalty income from third parties was $15 million for the year ended December 31, 2010 compared to $17 million for the year ended December 31, 2009. The decrease was related to lower tons mined by third parties from our coal reserves in the period-to-period comparison.

In the year ended December 31, 2009, mark-to-market adjustments for free standing coal sales options resulted in approximately a $2 million reversal of previously recognized unrealized losses. The reversal of the losses was primarily due to the decrease in market price of coal in 2009 compared to 2008. No such transactions existed in the year ended December 31, 2010.

Other income increased $1 million due to various transactions that occurred throughout both periods, none of which were individually material.

Other coal segment total costs were $698 million for the year ended December 31, 2010 compared to $613 million for the year ended December 31, 2009. The increase of $85 million was due to the following items:

Closed and idle mine costs increased approximately $77 million for the year ended December 31, 2010 to $215 million from $138 million for the year ended December 31, 2009. The increase in closed and idle mine costs was primarily related to additional reclamation liabilities recognized at the Fola mining operation in West Virginia. As a result of market conditions, permitting issues, new regulatory requirements and resulting changes in mine plans, the reclamation liability associated with the Fola operation increased approximately $81 million. Additional closed and idle mine costs in 2010 were also related to a $14 million charge as a result of a change in the mine plan at Mine 84. As a result of the mine plan change, a portion of the previously developed area of the mine has been abandoned. These increases were offset, in part, by approximately $18 million for changes in the operational status of various other mines, between idled and operating, throughout both periods which resulted in lower idled mine costs in 2010. Shoemaker Mine was idled throughout 2009 while the track haulage system was converted to a belt haulage system. This mine was in production throughout 2010.

Litigation expense of $25 million was recognized for the year ended December 31, 2010 related to a settlement that was reached in June 2010. The litigation was related to water discharge from our Buchanan Mine being stored in mine voids of adjacent properties which were leased by CONSOL Energy subsidiaries.

Cost of goods sold and other charges have increased approximately $13 million related to excess purchase price over appraised values for various land purchases that have been made throughout the year. Accounting guidance requires assets purchased to be recognized at the appraised value; synergies

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and related specific value to CONSOL Energy cannot be reflected as an asset. Various land deals in strategic areas for items such as refuse ponds, overland belts and various other key projects often require premiums over fair value, thus resulting in additional expense to CONSOL Energy at the time of the transaction.

Litigation settlement expense of $11 million was recognized for the year ended December 31, 2010 related to the sale of the Jones Fork Mining Complex.

Cost of goods sold and other charges have increased approximately $8 million due to various asset abandonments throughout the period, none of which were individually material. These abandonments primarily related to engineering work, permitting work and mapping work for miscellaneous projects that are no longer being pursued by the Company.

Purchased coal consists of costs from processing purchased coal in our preparation plants for blending purposes to meet customer coal specifications, coal purchased and sold directly to the customer and costs for processing third party coal in our preparation plants. These costs were $40 million for the year ended December 31, 2010 compared to $46 million for the year ended December 31, 2009. The decrease of $6 million was primarily due to reduced purchased coal volumes in the period-to-period comparison.

Litigation expense of $17 million was recognized for the year ended December 31, 2009 related to amounts accrued for the settlement of the Levisa Action and the Pobst/Combs Action. This litigation related to depositing water in mine voids which a subsidiary of CONSOL Energy leased.

Freight expense is based on weight of coal shipped, negotiated freight rates and method of transportation (i.e. rail, barge, truck, etc.) used by the customers to which CONSOL Energy contractually provides transportation services. Freight expense is offset in freight revenue. Freight expense was $126 million in the year ended December 31, 2010 compared to $149 million for the year ended December 31, 2009. The decrease of $23 million was primarily due to fewer tons shipped on CONSOL Energy freight contracts in the period-to-period comparison.

Other costs have decreased $3 million primarily due to various contingent liabilities related to potential legal settlements as well as various other transactions that have occurred throughout both periods, none of which are individually material.

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TOTAL GAS SEGMENT ANALYSIS for the year ended December 31, 2010 compared to the year ended December 31, 2009:

The gas segment contributed $180 million to earnings before income tax for the year ended December 31, 2010 compared to $263 million for the year ended December 31, 2009. Variances by the individual gas segments are discussed below.

	For the Year Ended December 31, 2010					Difference to Year Ended December 31, 2009				
	CBM	Conven-tional	Marcellus	Other Gas	Total Gas	CBM	Conven-tional	Marcellus	Other Gas	Total Gas
Sales:										
Produced	$ 567	$ 116	$ 48	$ 9	$ 740	$ (27)	$ 108	$ 27	$ 5	$ 113
Related Party	6				6	3				3
Total Outside Sales	573	116	48	9	746	(24)	108	27	5	116
Gas Royalty Interest				63	63				22	22
Purchased Gas				11	11				4	4
Other Income				5	5					
Total Revenue and Other Income	573	116	48	88	825	(24)	108	27	31	142
Lifting	50	30	5	2	87	1	26	4	1	32
Gathering	97	18	10	3	128	9	17	5	1	32
General & Administration	65	22	8	(2)	93	3	21	4	(2)	26
Depreciation, Depletion and Amortization	113	50	20	7	190	19	46	13	5	83
Gas Royalty Interest				54	54				22	22
Purchased Gas				10	10				4	4
Exploration and Other Costs				25	25				8	8
Other Corporate Expenses				56	56				23	23
Interest Expense				7	7				(1)	(1)
Total Cost	325	120	43	162	650	32	110	26	61	229
Earnings (Loss) Before Noncontrolling Interest and Income Tax	248	(4)	5	(74)	175	(56)	(2)	1	(30)	(87)
Noncontrolling Interest				(5)	(5)				(4)	(4)
Earnings (Loss) Before Income Tax	$ 248	$ (4)	$ 5	$ (69)	$ 180	$ (56)	$ (2)	$ 1	$ (26)	$ (83)

COALBED METHANE (CBM) GAS SEGMENT:

The CBM segment contributed $248 million to the total company earnings before income tax for the year ended December 31, 2010 compared to $304 million for the year ended December 31, 2009. The CBM segment revenue and cost components on a per unit basis are as follows:

	2010	2009	Variance	Percent Change
Produced gas CBM sales volumes (in billion cubic feet)	91.4	86.9	4.5	5.2%
Average CBM sales price per thousand cubic feet sold	$ 6.27	$ 6.87	$ (0.60)	(8.7)%
Average CBM lifting costs per thousand cubic feet sold	$ 0.54	$ 0.57	$ (0.03)	(5.3)%
Average CBM gathering costs per thousand cubic feet sold	$ 1.06	$ 1.01	$ 0.05	5.0%
Average CBM general & administrative costs per thousand cubic feet sold	$ 0.70	$ 0.71	$ (0.01)	(1.4)%
Average CBM depreciation, depletion and amortization costs per thousand cubic feet sold	$ 1.24	$ 1.08	$ 0.16	14.8%

Total CBM costs per thousand cubic feet sold	$ 3.54	$ 3.37	$ 0.17	5.0%
Margin	$ 2.73	$ 3.50	$ (0.77)	(22.0)%

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CBM sales revenues were $573 million for the year ended December 31, 2010 compared to $597 million for the year ended December 31, 2009. The decrease was primarily due to the 8.7% reduction in average price per thousand cubic feet sold, offset, in part, by the 5.2% increase in volumes sold. The decrease in CBM average sales price is the result of various gas swap transactions at a lower average price as compared to the prior year. These gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 50.5 billion cubic feet of our produced CBM gas sales volumes for the year ended December 31, 2010 at an average price of $7.73 per thousand cubic feet. These financial hedges represented approximately 51.6 billion cubic feet of our produced CBM gas sales volumes for the year ended December 31, 2009 at an average price of $8.76 per thousand cubic feet. Average gas sales prices excluding the impact of hedging were $4.47 per thousand cubic feet in 2010 compared to $4.13 per thousand cubic feet in 2009. CBM sales volumes increased 4.5 billion cubic feet primarily due to additional wells coming online from our on-going drilling program. We had 3,945 net CBM Wells at December 31, 2010 compared to 3,688 net CBM wells at December 31, 2009. Also, 2009 CBM volumes were lower by approximately 1.2 billion cubic feet of deferrals related to the idling of the Buchanan Mine for approximately five months during 2009.

Total costs for the CBM gas segment were $325 million for the year ended December 31, 2010 compared to $293 million for the year ended December 31, 2009. The $32 million increase in total costs in the period-to-period comparison reflects the 5.0% increase in average unit costs and the 5.2% increase in sales volumes.

CBM lifting costs were $50 million for the year ended December 31, 2010 compared to $49 million for the year ended December 31, 2009. Average CBM lifting costs per unit were $0.54 per thousand cubic feet for 2010 compared to $0.57 per thousand cubic feet for 2009. The improvement in average CBM lifting costs per unit was due to lower salt water disposal costs attributable to recycling the water produced from our wells to be used in hydraulic fracturing of new wells. Previously, fees were incurred to dispose of the salt water produced from our wells. Unit costs were also improved due to higher volumes of CBM gas sold in the period-to-period comparison resulting in fixed costs being spread over additional volumes, lowering the average per unit costs. These improvements were offset, in part, by higher severance taxes. Higher severance taxes were the result of average market price increases, excluding the impact of our hedging program. Severance taxes are also higher as a result of the Buchanan County, Virginia severance tax settlement which changed the deductions allowed in the calculation of severance tax due when the price of gas falls between certain ranges. See Note 24 Commitments and Contingent Liabilities in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion.

CBM Gathering costs were $97 million for the year ended December 31, 2010 compared to $88 million for the year ended December 31, 2009. Average CBM gathering cost were $1.06 per thousand cubic feet sold for the year ended December 31, 2010 compared to $1.01 per thousand cubic feet sold for the year ended December 31, 2009. Higher average unit costs were related to higher power costs attributable to utility rate increases in the period-to-period comparison as well as increased usage. Higher average unit costs were also attributable to additional in-transit costs related to additional capacity of firm transportation being purchased after 2009 to assure delivery of additional volumes being produced. These cost increases were offset, in part, by the 5.2% increase in volumes sold.

General and administrative costs attributable to the Total Gas segment have increased $26 million to $93 million for the year ended December 31, 2010 compared to $67 million for the year ended December 31, 2009. The increase was attributable to additional staffing and additional corporate service charges from CONSOL Energy. With the Dominion Acquisition, which closed on April 30, 2010, the majority of the operational support personnel were retained. Total Company general and administrative costs have also increased, as explained previously, which resulted in additional charges being allocated to all segments.

General and administrative costs attributable to the CBM gas segment were $65 million for the year ended December 31, 2010 compared to $62 million for the year ended December 31, 2009. General and administrative expenses attributable to the Total Gas segment are allocated to each individual gas segment based on a

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combination of production and employee counts. Although Total Gas general and administrative costs have increased $26 million, as discussed above, the percentage allocated to the CBM segment is lower, on a unit basis, as the result of CBM production volumes to total gas volumes produced being lower primarily due to the Dominion Acquisition.

Depreciation, depletion and amortization attributable to the CBM segment was $113 million for the year ended December 31, 2010 compared to $94 million for the year ended December 31, 2009. There was approximately $87 million, or $0.95 per unit-of-production, of depreciation, depletion and amortization related to CBM gas and related well equipment that was reflected on a units-of-production method of depreciation in the year ended December 31, 2010. The unit-of-production portion of depreciation, depletion and amortization was $71 million, or $0.82 per unit-of-production in the year ended December 31, 2009. The CBM unit-of-production rate used to calculate depreciation in the current year is generally calculated using the net book value of assets divided by either proved or proved developed reserves at the previous year end. The in-field drilling program and certain assets acquired in the Dominion Acquisition caused the rate to increase. There was approximately $26 million, or $0.29 per thousand cubic feet of depreciation, depletion and amortization related to gathering and other equipment that is reflected on a straight-line basis for the year ended December 31, 2010. The straight-line component was $23 million, or $0.26 per thousand cubic feet for the year ended December 31, 2009. The increase was related to additional gathering assets placed in service after 2009, offset, in part, by the increase in volumes in the period-to-period comparison.

CONVENTIONAL SEGMENT:

The conventional segment had a loss before income tax of $4 million for the year ended December 31, 2010 compared to a loss before income tax of $2 million for the year ended December 31, 2009. The conventional segment revenue and cost components on a per unit basis are as follows:

	2010	2009	Variance	Percent Change
Produced gas Conventional sales volumes (in billion cubic feet)	24.6	1.7	22.9	1,347.1%
Average Conventional sales price per thousand cubic feet sold	$ 4.73	$ 4.33	$ 0.40	9.2%
Average Conventional lifting costs per thousand cubic feet sold	$ 1.24	$ 2.76	$ (1.52)	(55.1)%
Average Conventional gathering costs per thousand cubic feet sold	$ 0.75	$ 0.59	$ 0.16	27.1%
Average Conventional general & administrative costs per thousand cubic feet sold	$ 0.88	$ 0.46	$ 0.42	91.3%
Average Conventional depreciation, depletion and amortization costs per thousand cubic feet sold	$ 2.05	$ 2.30	$ (0.25)	(10.9)%
Total Conventional costs per thousand cubic feet sold	$ 4.92	$ 6.11	$ (1.19)	(19.5)%
Margin	$ (0.19)	$ (1.78)	$ 1.59	(89.3)%

Conventional segment sales revenues were $116 million for the year ended December 31, 2010 compared to $8 million for the year ended December 31, 2009. Conventional sales volumes increased 22.9 billion cubic feet for the year ended December 31, 2010 primarily due to the Dominion Acquisition. Approximately 95% of the acquired producing wells were conventional type wells. There were 8,517 net conventional wells at December 2010 compared to 195 net conventional wells at December 31, 2009. No conventional gas volumes were hedged in 2010 or 2009.

Total costs for the conventional segment were $120 million for the year ended December 31, 2010 compared to $10 million for the year ended December 31, 2009. The increase of $110 million is attributable to additional volumes sold in the period-to-period comparison, offset, in part, by lower average unit costs sold. Conventional average unit costs have decreased due to the significant increase in volumes related to production from wells acquired in the Dominion Acquisition. A detailed analysis of cost categories is not meaningful due to the significant change in this segment related to the Dominion Acquisition and will therefore not be presented.

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General and administrative costs attributable to the Total Gas segment are allocated to each individual gas segment based on a combination of production and employee counts. Conventional volumes are higher as a percent of total gas produced volumes in the period-to-period comparison and therefore, additional general and administrative costs have been allocated to the conventional gas segment in 2010.

MARCELLUS SEGMENT:

The Marcellus segment contributed $5 million to the total company earnings before income tax for the year ended December 31, 2010 compared to $4 million for the year ended December 31, 2009. The Marcellus segment revenue and cost components on a per unit basis are as follows:

	2010	2009	Variance	Percent Change
Produced gas Marcellus sales volumes (in billion cubic feet)	10.2	5.0	5.2	104.0%
Average Marcellus sales price per thousand cubic feet sold	$ 4.68	$ 4.24	$ 0.44	10.4%
Average Marcellus lifting costs per thousand cubic feet sold	$ 0.48	$ 0.12	$ 0.36	300.0%
Average Marcellus gathering costs per thousand cubic feet sold	$ 1.01	$ 1.12	$ (0.11)	(9.8)%
Average Marcellus general & administrative costs per thousand cubic feet sold	$ 0.75	$ 0.74	$ 0.01	1.4%
Average Marcellus depreciation, depletion and amortization costs per thousand cubic feet sold	$ 1.93	$ 1.47	$ 0.46	31.3%
Total Marcellus costs per thousand cubic feet sold	$ 4.17	$ 3.45	$ 0.72	20.9%
Margin	$ 0.51	$ 0.79	$ (0.28)	(35.4)%

The increase in Marcellus average sales price was the result of an improvement in general market prices and various gas swap transactions that occurred in the year ended December 31, 2010. These gas swap transactions qualify as financial cash flow hedges that exist parallel to the underlying physical transactions. These financial hedges represented approximately 1.6 billion cubic feet of our produced Marcellus gas sales volumes for the year ended December 31, 2010 at an average price of $5.05 per thousand cubic feet. There were no gas swap transactions for the Marcellus segment that occurred for the year ended December 31, 2009. The increase in sales volumes was primarily due to additional wells coming online from our on-going drilling program. At December 31, 2010 there were 52 Marcellus Shale wells in production including 17 wells acquired in the Dominion Acquisition. At December 31, 2009 there were 22 Marcellus Shale wells in production.

Total costs for the Marcellus segment were $43 million for the year ended December 31, 2010 compared to $17 million for the year ended December 31, 2009. The increase was primarily due to the additional sales volumes and higher average unit costs.

Marcellus lifting costs were $5 million for the year ended December 31, 2010 compared to $1 million for the year ended December 31, 2009. Average Marcellus lifting costs were $0.48 per thousand cubic feet in 2010 compared to $0.12 per thousand cubic feet in 2009. The increase in average lifting costs per unit sold was due to increased road repairs and other maintenance expense primarily related to the additional number of wells drilled in the current period. Salt water disposal fees were also higher in the period-to-period comparison due to the higher volume of water produced from additional wells. These increases in costs were offset, in part, by the additional volume of Marcellus gas sold in the period-to-period comparison.

Marcellus gathering costs were $10 million for the year ended December 31, 2010 compared to $5 million for the year ended December 31, 2009. Average gathering cost per unit sold was $1.01 per thousand cubic feet for the year ended December 31, 2010 compared to $1.12 per thousand cubic feet for the year ended December 31, 2009. Lower average gathering cost per unit was primarily attributable to the 104.0% increase in volumes sold. This improvement was offset, in part, by higher power and security costs. Higher power costs were related to higher rates being charged by utility companies in the period-to-period comparison. Higher security costs were related to additional security needs at various Marcellus gathering stations.

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General and administrative costs attributable to the Marcellus gas segment were $8 million for the year ended December 31, 2010 compared to $4 million for the year ended December 31, 2009. Average general and administrative costs on a per unit sold basis were $0.75 per thousand cubic feet for the year ended December 31, 2010 compared to $0.74 per thousand cubic feet for the year ended December 31, 2009. General and administrative costs attributable to the Total Gas segment are allocated to each individual gas segment based on a combination of production and employee counts. The total general and administrative cost increases, as discussed previously, were offset, in part, by higher volumes of gas produced from Marcellus wells.

Depreciation, depletion and amortization attributable to the Marcellus segment was $20 million for the year ended December 31, 2010 compared to $7 million for the year ended December 31, 2009. There was approximately $18 million, or $1.73 per unit-of-production, of depreciation, depletion and amortization related to Marcellus gas and related well equipment that was reflected on a units-of-production method of depreciation in the year ended December 31, 2010. The unit-of-production portion of depreciation, depletion and amortization was $6 million, or $1.27 per unit-of-production in the year ended December 31, 2009. The Marcellus unit-of-production rate used to calculate depreciation in the current year is generally calculated using the net book value of assets divided by either proved or proved developed reserves at the previous year end. The investment in drilling activities increased in higher proportion than the related gas reserves in the current period, which resulted in a higher per unit rate. There was approximately $2 million, or $0.20 per thousand cubic feet of depreciation, depletion and amortization related to gathering and other equipment that is reflected on a straight-line basis for the year ended December 31, 2010. The straight-line component was $1 million, or $0.20 per thousand cubic feet for the year ended December 31, 2009. The increase was related to additional gathering assets placed in service after 2009, offset, in part, by the increase in volumes in the period-to-period comparison.

OTHER GAS SEGMENT:

The Other gas segment includes activity not assigned to CBM, Conventional or Marcellus gas segments. This segment includes purchased gas activity, gas royalty interest activity, exploration and other costs, other corporate expenses, and miscellaneous operational activity not assigned to a specific gas segment. The other gas segment had a loss before income tax of $69 million for the year ended December 31, 2010 compared to a loss before income tax of $43 million for the year ended December 31, 2009.

Other gas sales volumes are primarily related to production from the Chattanooga Shale in Tennessee. Revenue from this operation was approximately $9 million for the year ended December 31, 2010 compared to $4 million for the year ended December 31, 2009. There was 1.7 billion cubic feet sold from this area for the year ended December 31, 2010 compared to 0.8 billion cubic feet for the year ended December 31, 2009. Total costs related to these other sales were $10 million for the year ended December 31, 2010 compared to $5 million for the year ended December 31, 2009. The increase in costs in the period-to-period comparison was primarily due to higher depreciation, depletion and amortization attributable to the additional 0.9 billion cubic feet of gas produced and higher unit-of-production rates. The higher units-of-production rates were related to a higher proportion of capital assets placed in service versus the proportion of proved developed reserve additions. A per unit analysis of the other operating costs in Chattanooga is not meaningful due to the low volumes produced in the period-to-period analysis.

Royalty interest gas sales represent the revenues related to the portion of production belonging to royalty interest owners sold by the CONSOL Energy gas segment. The changes in market prices, contractual differences among leases, and the mix of average and index prices used in calculating royalties contributed to the period-to-period change. Royalty interest gas sales revenues were $63 million for the year ended December 31, 2010 compared to $41 million for the year ended December 31, 2009.

	2010	2009	Variance	Percent Change
Gas Royalty Interest Sales Volumes (in billion cubic feet)	14.2	9.8	4.4	44.9%
Average Sales Price Per thousand cubic feet sold	$ 4.41	$ 4.17	$ 0.24	5.8%

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Purchased gas sales volumes represent volumes of gas we sold at market prices that were purchased from third-party producers. Purchased gas sales revenues were $11 million for the year ended December 31, 2010 compared to $7 million for the year ended December 31, 2009.

	2010	2009	Variance	Percent Change
Purchased Gas Sales Volumes (in billion cubic feet)	2.0	1.6	0.4	25.0%
Average Sales Price Per thousand cubic feet sold	$ 5.48	$ 4.46	$ 1.02	22.9%

Other income was consistent at $5 million for the years ended December 31, 2010 and 2009.

Royalty interest gas costs represent the costs related to the portion of production belonging to royalty interest owners sold by the CONSOL Energy gas segment. The changes in market prices, contractual differences among leases, and the mix of average and index prices used in calculating royalties contributed to the period-to-period change. Royalty interest gas sales costs were $54 million for the year ended December 31, 2010 compared to $32 million for the year ended December 31, 2009.

	2010	2009	Variance	Percent Change
Gas Royalty Interest Sales Volumes (in billion cubic feet)	14.2	9.8	4.4	44.9%
Average Cost Per thousand cubic feet sold	$ 3.78	$ 3.30	$ 0.48	14.5%

Purchased gas volumes represent volumes of gas purchased from third-party producers that we sell. Purchased gas volumes also reflect the impact of pipeline imbalances. The higher average cost per thousand cubic feet is due to overall price changes, contractual differences among customers and the pipeline imbalance. Purchased gas costs were $10 million for the year ended December 31, 2010 compared to $6 million for the year ended December 31, 2009.

	2010	2009	Variance	Percent Change
Purchased Gas Volumes (in billion cubic feet)	1.9	1.7	0.2	11.8%
Average Cost per thousand cubic feet sold	$ 5.14	$ 3.75	$ 1.39	37.1%

Exploration and other costs were $25 million for the year ended December 31, 2010 compared to $17 million for the year ended December 31, 2009. The $8 million increase was made up of the following items:

	2010	2009	Variance	Percent Change
Dry hole and lease expiration costs	$ 16	$ 10	$ 6	60.0%
Land and delay rentals	5	4	1	25.0%
Exploration	4	3	1	33.3%
Total Exploration and Other Costs	$ 25	$ 17	$ 8	47.1%

Dry hole and lease expiration costs were $6 million higher in the period-to-period comparison primarily due to lease surrenders in the current year, offset, in part, by lower dry wells drilled in the year ended December 31, 2010.

Land and delay rentals, as well as Exploration, both increased $1 million in the period-to-period comparison due to various transactions that occurred throughout both periods, none of which were individually material.

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Other corporate expenses were $56 million for the year ended December 31, 2010 compared to $33 million for the year ended December 31, 2009. The $23 million increase was due to the following items:

	2010	2009	Variance	Percent Change
Short-term incentive compensation	$ 24	$ 16	$ 8	50.0%
Stock-based compensation	16	11	5	45.5%
Variable interest earnings	4		4	100.0%
Bank fees	4		4	100.0%
Financing and acquisition fees	3		3	100.0%
Contract settlement		3	(3)	(100.0)%
Other	5	3	2	66.7%
Total Other Corporate Expenses	$ 56	$ 33	$ 23	69.7%

The short-term incentive compensation program is designed to increase compensation to eligible employees when the gas segment reaches predetermined targets for safety, production and unit cost goals. Short-term incentive compensation expense is higher in 2010 due to a 13% increase in employee counts, as well as an increase in the short-term incentive compensation allocation to the gas segment. Additional employees in the total company general and administrative area were primarily related to support staff retained in the Dominion Acquisition and additional hiring to support operations.

Stock-based compensation is higher in the period-to-period comparison primarily due to the conversion of the CNX Gas performance share units to CONSOL Energy restricted stock units in the year ended December 31, 2009. The conversion resulted in a reduction of approximately $4 million of expense in 2009. Additional expense was also related to stock-based compensation allocated from CONSOL Energy to the gas segment in 2010. These increases were offset, in part, by the non-vested CNX Gas stock options being terminated in relation to the CNX Gas take-in transaction. The expense previously recognized for these options was reversed on the gas segment. All stock-based compensation is now allocated from CONSOL Energy.

Variable interest earnings are related to various adjustments a third party entity has reflected in its financial statements. CONSOL Energy holds no ownership interest, but guarantees bank loans the entity holds related to its purchases of drilling rigs. CONSOL Energy is also the main customer of the third party, and based on analysis is the primary beneficiary. Therefore, the entity is fully consolidated and then the impact is fully reversed in the noncontrolling interest line discussed below.

Banks fees are higher in the period-to-period comparison due to amending and extending the revolving credit facility related to the gas segment.

Financing and acquisition fees are related to legal expenses for the special committee, formed during the CNX Gas take-in transaction, and are primarily related to the shareholder litigation.

The year ended December 31, 2009 includes $3 million of expense related to a contract buyout with a driller in order to mitigate idle rig charges in certain areas where drilling was not expected to increase in the near term.

Other corporate expense increased $2 million in the year-to-year comparison primarily due to unused firm transportation charges not being allocated to the operating gas segments and various other transactions that occurred throughout both periods, none of which were individually material.

Interest expense was $7 million for the year ended December 31, 2010 compared to $8 million for the year ended December 31, 2009. Interest is incurred by the gas segment on the gas segment revolving credit facility, a capital lease and debt held by a variable interest entity. No significant changes in these components occurred in the period-to-period comparison.

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Noncontrolling interest represents 100% of the earnings impact of a third party which has been determined to be a variable interest entity, in which the CONSOL Energy gas segment holds no ownership interest, but is the primary beneficiary. The CONSOL Energy gas segment has been determined to be the primary beneficiary due to guarantees of the third party s bank debt related to their purchase of drilling rigs. The third party entity provides drilling services primarily to the CONSOL Energy gas segment. CONSOL Energy consolidates the entity and then reflects 100% of the impact as noncontrolling interest. The consolidation does not significantly impact any amounts reflected in the gas segment income statement. The variance in the noncontrolling interest amounts reflects the third party s variance in earnings in the period-to-period comparison.

OTHER SEGMENT ANALYSIS for the year ended December 31, 2010 compared to the year ended December 31, 2009:

The other segment includes activity from sales of industrial supplies, transportation operations and various other corporate activities that are not allocated to the coal or gas segment. The other segment had a loss before income tax of $249 million for the year ended December 31, 2010 compared to a loss of $22 million for the year ended December 31, 2009. The other segment also includes total company income tax expense of $109 million for the year ended December 31, 2010 and $221 million for the year ended December 31, 2009.

	2010	2009	Variance	Percent Change
Sales-Outside	$ 297	$ 273	$ 24	8.8%
Other Income	29	29		
Total Revenue	326	302	24	7.9%
Cost of Goods Sold and Other Charges	349	267	82	30.7%
Depreciation, Depletion & Amortization	18	20	(2)	(10.0)%
Taxes Other Than Income Tax	10	13	(3)	(23.1)%
Interest Expense	198	24	174	725.0%
Total Costs	575	324	251	77.5%
Loss Before Income Tax	(249)	(22)	(227)	(1,031.8)%
Income Tax	109	221	(112)	(50.7)%
Net Loss	$ (358)	$ (243)	$ (115)	(47.3)%

Industrial Supplies:

Total revenues from industrial supply operations were $195 million for the year ended December 31, 2010 compared to $196 million for the year ended December 31, 2009.

Total costs related to industrial supply sales were $197 million for the year ended December 31, 2010 compared to $190 million for the year ended December 31, 2009. The $7 million increase in expense is primarily due to changes in last-in-first-out valuations.

Transportation operations:

Total revenue from transportation operations was $114 million for the year ended December 31, 2010 compared to $84 million for the year ended December 31, 2009. The $30 million increase was primarily attributable to additional through-put tons at the Baltimore terminal in the period-to-period comparison.

Total costs related to transportation operations were $81 million for the year ended December 31, 2010 compared to $70 million for the year ended December 31, 2009. The $11 million increase was primarily related to the additional through-put tons at the Baltimore terminal in the period-to-period comparison.

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Miscellaneous Other:

Other income was $17 million for the year ended December 31, 2010 compared to $22 million for the year ended December 31, 2009. The $5 million decrease was attributable to $6 million of Other Income for the acceleration of a deferred gain associated with the initial sale-leaseback of the Company s previous headquarters in 2009. This was offset by $1 million related to various transactions that occurred throughout both periods, none of which were individually material.

Other corporate costs include interest cost, acquisition and financing costs and various other miscellaneous corporate charges. Total other costs were $297 million for the year ended December 31, 2010 and $64 million for the year ended December 31, 2009. Other corporate costs increased $233 million due to the following:

- Interest expense of $198 million was incurred in the year ended December 31, 2010 compared to $24 million in the year ended December 31, 2009. The increase of $174 million was primarily attributable to the additional interest expense on the long-term bonds that were issued in conjunction with the Dominion Acquisition.

- Financing and acquisition fees of $62 million were incurred in the year ended December 31, 2010 primarily related to the equity and debt issuance that raised approximately $4.6 billion dollars. These fees also include costs related to extending and refinancing the CONSOL Energy revolving credit facility, the Dominion Acquisition and the purchase of the CNX Gas noncontrolling interest.

- Bank fees of $16 million were incurred in the year ended December 31, 2010 compared to $5 million in the year ended December 31, 2009. The increase of $11 million was primarily related to the refinanced revolving credit facility.

- Fees related to the disposition of non-core assets of $3 million were incurred in the year ended December 31, 2010.

- Various other corporate expenses were $21 million in the year ended December 31, 2010 compared to $18 million in the year ended December 31, 2009. The increase of $3 million was due to various transactions that occurred throughout both periods, none of which were individually material.

- In the year ended December 31, 2010, there was $3 million of reduced expense related to an adjustment to assumptions used in the 2009 cease use of the Company s previous headquarter liability. The year ended December 31, 2009 included $13 million of expense related to the cease use of the facility. These transactions resulted in a $16 million improvement in the period-to-period comparison.

- Severance payments of $4 million were incurred in the year ended December 31, 2009 related to various layoffs that were necessary due to the economic downturn that occurred.

Income Taxes:

The effective income tax rate was 23.4% for the year ended December 31, 2010 compared to 28.1% for the year ended December 31, 2009. The effective tax rate is sensitive to the relationship between pre-tax earnings and percentage depletion. The proportion of coal pre-tax earnings and gas pre-tax earnings also impacts the benefit of percentage depletion on the effective tax rate. The mix of pre-tax income by state may also impact the overall effective tax rate. The pre-tax income mix by state has changed in the period-to-period comparison due to the Dominion Acquisition. See Note 6 Income Taxes in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional explanation of the effective tax rate change in the period-to-period comparison.

	2010	2009	Variance

				Percent Change
Total Company Earnings Before Income Taxes	$ 468	$ 788	$ (320)	(40.6)%
Income Tax Expense	$ 109	$ 221	$ (112)	(50.7)%
Effective Income Tax Rate	23.4%	28.1%	(4.7)%	

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Results of Operations

Year Ended December 31, 2009 Compared with Year Ended December 31, 2008

Net Income Attributable to CONSOL Energy Shareholders

CONSOL Energy reported net income attributable to CONSOL Energy shareholders of $540 million, or $2.95 per diluted share, for the year ended December 31, 2009. Net income attributable to CONSOL Energy shareholders was $442 million, or $2.40 per diluted share, for the year ended December 31, 2008. See below for a detailed explanation by segment of the variance incurred in the period-to-period comparison.

The average sales price and total costs for all active coal operations was as follows:

	Year Ended December 31,			
	2009	**2008**	**Variance**	**Percent Change**
Average Sales Price per ton sold	$ 58.70	$ 47.61	$ 11.09	23.3%
Average Costs per ton sold	43.13	39.36	3.77	9.6%
Margin	$ 15.57	$ 8.25	$ 7.32	88.7%

The gas segment includes coalbed methane (CBM), conventional, Marcellus and other gas. The segments are determined based on activities from target strata. The other gas segment includes royalty interest activities, purchased gas activities and other activities assigned to the gas segment, but not allocated to each individual component. Prior to 2009, the gas segment was primarily made up of the CBM segment. Less than one percent of sales volumes were attributable to the conventional and Marcellus operations. Due to the insignificant amounts attributable to the conventional and Marcellus activities, a comparison of these operations will not be discussed.

The average sales price and total costs for all active gas operations was as follows:

	Year Ended December 31,			
	2009	**2008**	**Variance**	**Percent Change**
Average Sales Price per thousand cubic feet sold	$ 6.68	$ 8.99	$ (2.31)	(25.7)%
Average Costs per thousand cubic feet sold	3.44	3.66	(0.22)	(6.0)%
Margin	$ 3.24	$ 5.33	$ (2.09)	(39.2)%

The other segment includes industrial supplies activity, terminal and river service activity, income taxes and other business activities not assigned to the coal or gas segment.

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TOTAL COAL SEGMENT ANALYSIS for the year ended December 31, 2009 compared to the year ended December 31, 2008:

The Total Coal segment contributed $546 million to earnings before income tax for the year ended December 31, 2009 compared to $344 million for the year ended December 31, 2008.

	For the Year Ended December 31, 2009					Difference to Year Ended December 31, 2008				
	Steam Coal	High Vol Met Coal	Low Vol Met Coal	Other Coal	Total Coal	Steam Coal	High Vol Met Coal	Low Vol Met Coal	Other Coal	Total Coal
Sales:										
Produced Coal	$ 3,122	$	$ 249	$	$ 3,371	$ 399	$	$ (92)	$	$ 307
Purchased Coal				39	39				(79)	(79)
Total Outside Sales	3,122		249	39	3,410	399		(92)	(79)	228
Freight Revenue				149	149				(68)	(68)
Other Income	7			70	77	7			(51)	(44)
Total Revenue and Other Income	3,129		249	258	3,636	406		(92)	(198)	116
Costs and Expenses:										
Total operating costs	1,740		116	304	2,160	(25)		(21)	24	(22)
Total provisions	180		16	28	224	(5)		1	(18)	(22)
Total administrative & other costs	144		10	99	253	(2)		(4)	27	21
Depreciation, depletion and amortization	258		13	33	304			(1)	6	5
Total Costs and Expenses	2,322		155	464	2,941	(32)		(25)	39	(18)
Freight Expense				149	149				(68)	(68)
Total Cost	2,322		155	613	3,090	(32)		(25)	(29)	(86)
Earnings (Loss) Before Income Taxes	$ 807	$	$ 94	$ (355)	$ 546	$ 438	$	$ (67)	$ (169)	$ 202

STEAM COAL SEGMENT:

The steam coal segment contributed $807 million to total company earnings before income tax for the year ended December 31, 2009 compared to $369 million for the year ended December 31, 2008.

Steam coal revenue was $3,122 million for the year ended December 31, 2009 compared to $2,723 million for the year ended December 31, 2008. The increase of $399 million was attributable to the higher average price per ton sold, offset, in part, by lower sales volumes of company produced steam coal sold.

	2009	2008	Variance	Percent Change
Produced Steam Tons Sold (in millions)	55.1	61.4	(6.3)	(10.3)%
Average Sales Price Per Steam Ton Sold	$ 56.64	$ 44.31	$ 12.33	27.8%
Average Operating Costs Per Steam Ton Sold	$ 31.57	$ 28.70	$ 2.87	10.0%
Average Provision Costs Per Steam Ton Sold	$ 3.27	$ 3.01	$ 0.26	8.6%
Average Selling, Administrative and Other Costs Per Steam Ton Sold	$ 2.60	$ 2.38	$ 0.22	9.2%
Average Depreciation, Depletion and Amortization Costs Per Steam Ton Sold	$ 4.68	$ 4.20	$ 0.48	11.4%
Total Costs Per Steam Ton Sold	$ 42.12	$ 38.29	$ 3.83	10.0%

Margin	$ 14.52	$ 6.02	$ 8.50	141.2%

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The increase in average sales price in the year-to-year comparison primarily reflects higher prices negotiated in previous periods when there was a significant increase in the global demand for coal. Sales of company produced steam coal shipments decreased in 2009 due to delivery deferments of Central and Northern Appalachian coals. Coal consumption by the electric power sector continued to decline during 2009.

Operating costs are made up of labor, supplies, maintenance, subsidence, taxes other than income, royalties and preparation plant charges related to the extraction and sale of coal. These costs are reviewed regularly by management and are considered to be the direct responsibility of mine management. Operating costs related to the steam coal segment were $1,740 million for the year ended December 31, 2009 compared to $1,765 million for the year ended December 31, 2008.

Higher average operating costs per unit for steam coal tons sold is primarily related to the following items:

- In general, average operating costs per unit increased due to the reduced amount of tons sold from CONSOL Energy mines. The reduction in tons sold reflected the weak economic environment which affected electricity generation and correspondingly the demand for coal. Fixed costs incurred at our mining operations were spread over fewer tons sold, which negatively impacted average unit costs.

- Supply costs per unit are higher in 2009 due to higher supply and maintenance costs at several locations. Additional supply and maintenance projects were related to additional preparation plant maintenance, additional belt advancement costs, additional mining equipment maintenance, additional roof support, additional use of contract labor to complete belt projects and additional water handling costs. These increased supply and maintenance costs were offset, in part, by fewer seals being constructed in previously mined areas. Average unit costs of supplies were also impacted by lower sales tons in the year-to-year comparison.

- Labor costs have increased due to the effects of wage increases at the union and non-represented mines. These contracts call for specified hourly wage increases in each year of the contract. The average increase in unit cost for labor was also impacted by lower sales volumes due to the economic environment as discussed above.

- Production taxes per steam ton sold increased due to higher average sales prices received for this coal.

- United Mine Workers of America (UMWA) health and retirement plan expenses increased over 2008 primarily due to the effects of the 2007 labor contract that requires additional contributions to be made into employee benefit funds. The contribution increase over 2008 was $0.42 per United Mine Worker of America hour worked. The average increase in unit costs for health and retirement plans was also impacted by lower sales tons in the year-to-year comparison.